IRENA

International Renewable Energy Agency

WEST AFRICAN POWER POOL: Planning and Prospects for Renewable Energy

About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international cooperation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity.
www.irena.org

Acknowledgements

IRENA prepared this report in close collaboration with Bruno Merven, at the Energy Research Centre, University of Cape Town, South Africa, who conducted major development work on with IRENA on the ECOWAS Renewable Energy Planning (EREP) too, provided modelling support in the development of scenarios for West Africa, and assisted with interpreting the results. The report benefited from review and consultations with the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE), as well as discussions at an IRENA-ECREEE workshop on energy planning on 10-12 December 2012 in Abidjan, Cote D'Ivoire. The workshop was attended by government and utility energy planning professionals from Benin, Burkina Faso, Cote D'Ivoire, Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone, and Togo. IRENA appreciates the active contributions of the participants, which have made the resulting work more policy-relevant. IRENA also acknowledges ECREEE's careful review of an earlier version of this publication.

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MODEL FILES DOWNLOAD

All data and results presented here are available on the IRENA website: www.irena.org/WAPP.

The analysis presented here corresponds to following version of the model files.

- MAINWAPP_2013-05-15_1526.zip (EREP model file)
- Demand_ALL_revised2012_AM.xlsx (energy demand data file)
- Transmission Data_02.xlsx (transmission data file)
- WAPP_Supply_16_BY_Wind_CIExist_Fixed.xlsm (Technology data file)
- 0REFERENCE_v12.xlsm (results file for the reference scenario)
- 1RE_v12.xlsm (results file for the renewable scenario)
- 1bRE_noInga_v12.xlsm (results file for the no CA import scenario)
- 1bRE_limTrade_v12.xlsm (results file for the energy security scenario)
- Summary_ECOWAS_v12c.xlsx
- Load_Calibration_all_01.xlsm

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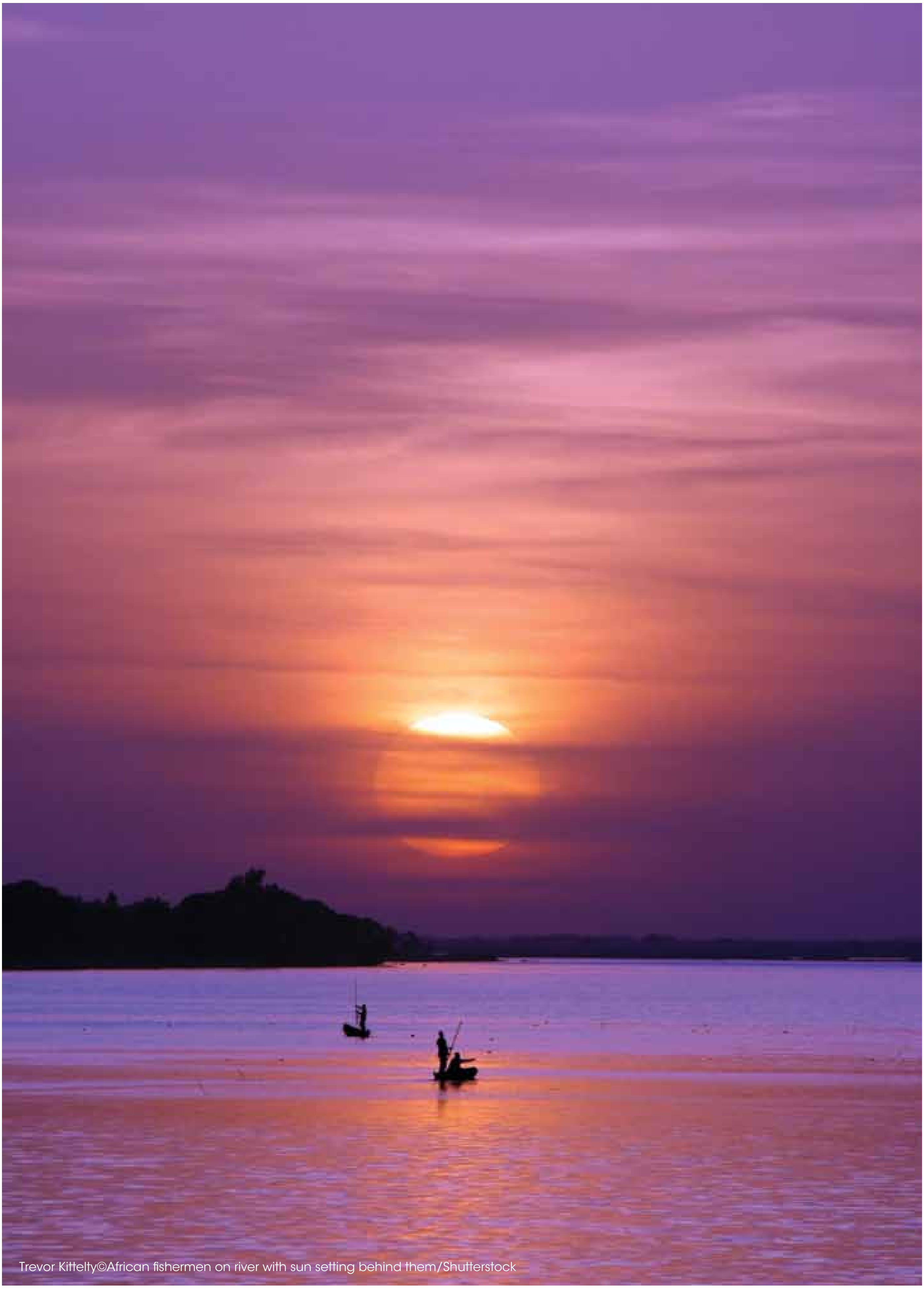
Galushko Sergey©Old compass and map background/Shutterstock

Abbreviations

CCGT	Combined Cycle Gas Turbine
CSP	Concentrated Solar Power
ECOWAS	Economic Community of West African States
ECREEE	ECOWAS Regional Centre for Renewable Energy and Energy Efficiency
EREP	ECOWAS Renewable Energy Planning tool
GHG	Greenhouse Gases
GWh	Gigawatt hours
IAEA	International Atomic Energy Agency
IIASA	International Institute of Applied System Analysis
IRENA	International Renewable Energy Agency
GJ	Gigajoules
kV	Kilovolt
LCOE	Levelised Cost of Electricity
MW	Megawatt
NREAP	National Renewable Energy Action Plans
OCGT	Open Cycle Gas Turbine
T&D	Transmission and Distribution
TWh	Terawatt hours
UNIDO	United Nations Industrial Development Organisation
USD	United States Dollars
WAPP	West African Power Pool



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Executive Summary

IRENA has developed a power sector planning tool for Western African countries called "EREP", for ECOWAS Renewable Energy Planning. This tool enables analysts to design a power system that meets various system requirements, including reliability. EREP also takes into account economically optimal configurations (including investment and operation costs) of the system to meet daily/seasonally fluctuating demand.

Using EREP, IRENA developed a renewable energy promotion scenario for continental ECOWAS countries. The scenario is intended to illustrate how EREP can be used and to provide a robust starting point for planning analysts to stimulate discussion about its assumptions and results. In this scenario, IRENA assessed the investment needs in power generation (on- and off-grid), in domestic transmission and distribution, as well as in international transmission networks to meet the growing demand in the region in the most affordable manner. Existing capital stock, replacement needs and committed investments were explicitly considered. Emphasis was given to integrating renewable technology generation into on- and off-grid power systems, taking into account the differences among generation technologies in responding to demand fluctuation. All continental ECOWAS countries were assessed jointly, providing insights on the need for investments into regional electricity interconnectors. All data and results presented here are available on the IRENA website: www.irena.org/WAPP.

IRENA's assessment shows that the share of the renewable technologies in the region could increase from the current 22% of electricity generation to as much as 52% in 2030, provided that the cost of these technologies continues to fall and fossil fuel prices continue to rise. In this scenario, nearly half of the envisaged capacity additions between 2010 and 2030 would be with renewable technologies. Mini-hydro generation technology could become significant for supplying rural electricity demand, so that by 2030, nearly 80% of rural electricity demand could be met by the technology. Total investment required in the region would amount to nearly USD 170 billion (undiscounted). Despite conservative assumptions on renewable resource availability and penetration limits for wind and solar technologies, the share of renewable energy technologies in 2030 under this scenario would be substantially higher than the regional target for renewables in the power sector (31% of on-grid power production from renewables by 2030), set by the ECOWAS Regional Renewable Policy. Hydro generation alone would account for 33% of the total generation.

While IRENA has used publicly available information to represent the current power supply infrastructure, further validation by local experts would enhance the model's robustness. Moreover, the assessment is based on certain assumptions, including (but not limited to) fuel costs, infrastructure development and policy developments. These may well be different from the perspective of the energy planners in the region. It is recommended that local experts explore different assumptions and develop and compare their own scenarios to analyse benefits and challenges associated with the accelerated deployment of renewables.

With the aim to assist ECOWAS member states in developing National Renewable Energy Action Plans (NREAPs) under the ECOWAS Regional Renewable Energy Policy, IRENA and ECREEE have begun enhancing EREP beyond what is documented in this report. Over the next two years, further methodological improvements regarding the representation of the RE technologies will be implemented, and local experts in the region will be engaged in a bid to improve the data. In parallel, IRENA, together with partner organisations, has been planning to set up capacity building support in the use of the energy system modelling approach for renewable energy planning.


Trevor Kittelty©A Tuareg man walking up a sand dune in the Sahara desert/Shutterstock

1. Introduction

Africa needs to significantly improve its electricity supply in order to enhance energy access for its growing population and provide the means for economic growth. Africa has great domestic renewable energy potential, which could be used to provide much needed energy in an affordable and secure manner, and to contribute to universal access to modern energy while avoiding negative environmental impact. A long-term vision is needed to make the best use of available domestic resources, given the long-lasting nature of energy infrastructure. Since different power supply technologies have different operational characteristics that could complement each other, the deployment of renewable technologies cannot be planned in isolation from the rest of a power system, but rather needs to be looked at from the perspective of their integration into the system.

The International Renewable Energy Agency (IRENA) aims to assist its member countries with energy system planning to make a transition to an energy system that makes maximum use of environmentally benign, fossil-free renewable technologies. IRENA's earlier work Scenarios and Strategies for Africa was a major input to the IRENA-Africa High Level Consultations on Partnership on Accelerating Renewable Uptake for Africa's Sustainable Development, held in Abu Dhabi in July 2011, at which Ministers of Energy and heads of delegation of African countries announced a communique recognising the IRENA's role in promoting renewable energy to accelerate Africa's development (IRENA 2011a).

IRENA has since taken up a number of research projects to provide a solid factual basis supporting policy decision-making. This report presents some of the energy system planning scenarios for the ECOWAS (Economic Community of West African States) region, which describe a long-term (i.e., till 2050) transition to a renewable-oriented future of national power systems in the region. This can be accelerated by taking into consideration the long-term cost-reduction potential of renewable energy technologies. Technically feasible and economically favourable transition paths were computed by an energy system modelling tool called EREP (ECOWAS Renewable Energy Planning tool), in which retirement of current power infrastructure, geographical distribution of renewable resources, generation adequacy of the system, among others, were taken into account. The assessment includes economic and social implications of adopting renewable energy, in terms of investment needs, fuel savings, energy savings, etc. This is a part of series of activities that IRENA has been conducting for all five power-pool regions in Africa, covering all continental African countries.

The EREP model is built on the database of the West African Power Pool (WAPP) system, which consists of existing generation units, international transmission lines and a range of future technology options. EREP calculates future configurations of the power system based on specified system requirements and to meet given, or fluctuating, energy demand. The configuration of the power system is defined primarily by achieving the minimisation of total energy costs over the planning period (i.e., 2010 - 2050).

WAPP recently published the Draft Final Report of the Update of the ECOWAS Revised Master Plan for the Generation and Transmission of Electrical Energy (WAPP, 2011), in which different power generation and transmission projects are analysed and evaluated from an economic and technical perspective. The economic evaluation of different planning scenarios, combining different policy actions and uncertainties was done using a power system optimisation tool. The WAPP Master Plan uses these scenarios to identify priority investment projects from a techno- economic perspective.

For this study, the reference scenario of the WAPP Master Plan was recreated using the EREP model, in order to show the compatibility of the EREP model approach with the WAPP Master Plan's underlining approach. This study's primary value addition is that insights from IRENA's latest analytical work on renewable technology development and renewable resource potentials are reflected in the database and modelling approach. The renewable scenario presented in this report shows that a more aggressive deployment of renewable technology than the one in the WAPP Master Plan reference scenario is feasible and even economical. Its secondary additional value is that the EREP model is built on a modelling framework that is well maintained and can be obtained free of charge. EREP is designed to be transferred to interested organisations in IRENA Member Countries so that they can use it to explore alternative scenarios for national and regional power sector development. Regional training programmes could also be organised upon request. Several EREP model tutorials have been developed by IRENA and ECREEE and made available at www.irena.org/WAPP.

EREP covers all the continental ECOWAS countries: Burkina Faso, Cote d'Ivoire, Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone, and Togo/Benin.


Wind Power in West Africa (ECREEE)

2. Overview of Methodology

EREP was developed using a modelling platform called MESSAGE. MESSAGE is a dynamic, bottom-up, multi-year energy system modelling framework applying linear and mixed-integer optimisation techniques. The modelling platform was originally developed at the International Institute of Applied System Analysis (IIASA), but has more recently been further enhanced by the International Atomic Energy Agency (IAEA). The modelling platform is the framework within which the actual model is developed.

The MESSAGE modelling platform consists of a database which needs to be populated with energy demand and load projections, economic and technical parameters of energy resources and energy supply options, including power plants, transmission and distribution lines, electricity trades and information regarding the existing capital stock and remaining life span. IRENA developed the EREP model by populating the database, configuring it to replicate the existing power infrastructure in each country and setting up a few scenarios in which alterative visions of the future development of a power system and the factors influencing it are quantified. EREP builds on earlier work done by the IAEA. Decisions about investment and operation of plants under consideration and generic plants are a result of the least-cost optimisation in MESSAGE. The least-cost optimisation procedure defines the operation and investment schedule that minimises the total discounted system costs (including investment costs, O&M costs, fuel costs, and any other user-defined costs) over the planning horizon while various system requirements (e.g., supply meets demand at a given time point, that there should be sufficient resources, capacity need to be in place to supply desired production) and user-defined constraints (e.g., reserve margin, speed of technology deployment, emission limits, policy targets) are met. The model reports on the investment and production mix of technologies and fuels that achieve a least-cost power system configuration to meet a given power demand. Economic and environmental implications associated with the identified least-cost power systems can be easily calculated using the model. The modelling framework allows the model to be configured to assess direct social associations (e.g., external costs, job creation effects, local economic impacts).

The model developed by the IAEA was further enhanced by IRENA in two regards. Firstly, additional aspects were included that are essential for the proper assessment of renewable energy technology deployment and secondly, the latest findings for renewable energy technology potential and cost development, based on a series of IRENA studies for Africa were considered. To better reflect the role of decentralised power options for which renewables can offer a significant cost advantage over fossil-based options, the power demand was split into three categories – industrial, urban and rural electricity use. This is important as the shape of the load curve and the connection to the grid differs markedly between categories. Different distributed generation options are available for each category. The set of renewable energy supply options was also expanded and significantly refined. The latest technology cost data and capacity factor data were used, based on IRENA cost-competitiveness and technology assessment studies. Data on the quantity and quality of renewable energy resources was updated and refined, using data collected during work on the IRENA-Renewable Energy Atlas.

In the EREP model, each country is modelled as a separate node inter-linked by transmission lines. Each node representing the power system of a single country is characterised as shown in Figure 1. Once the demand is specified, a technically feasible, least-cost power supply system that meets the given demand while satisfying all the constraints is computed by the model for the modelling period. The "least cost" is defined for the region as a whole and for the entire modelling period. EREP considers four types of power generation options, existing power plants, power plants to be commissioned, site-specific power plant projects under consideration (candidate projects), and non-site specific generic power plants. List of plants in the first three categories are taken from the WAPP Master Plan.

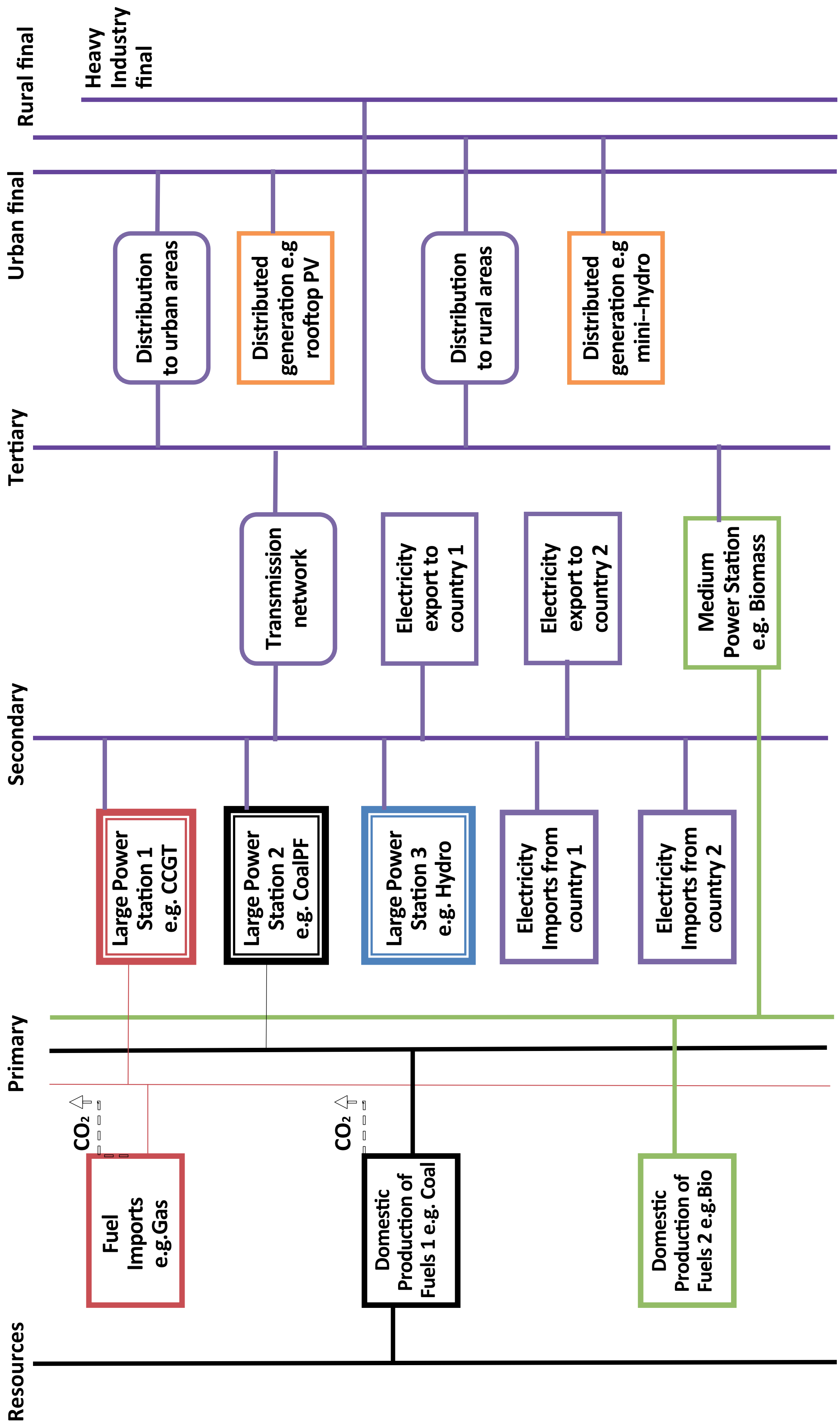

Figure 1. Country Power Sector Model Structure

3. Scenario Assumptions

3.1 GENERAL DEFINITION OF THE FOUR SCENARIOS

One Reference Scenario and three variations of renewable promotion scenarios (Renewable Energy Policy Scenario, No Inga Scenario, and an Energy Security Scenario) have been assessed. The Reference Scenario is compatible with the WAPP Master Plan reference scenario, but includes the mining demand (which is about 8% higher than the demand used in the reference scenario of the WAPP Master Plan for 2025). The system was optimised at the regional level, with electricity trade within the ECOWAS region allowed. Only those trans-border transmission projects currently under consideration (decided or candidate) are included as future options to be optimised by the model. Some important differences from the reference scenario in the WAPP Master Plan are:

» Inclusion of decentralised electricity supply options;

» Segregation of rural/urban/industrial electricity demand;

» Updating of renewable energy resource potentials and technology cost data; and

» Annual generation for a given hydropower project is assessed conservatively using a "dry year" generation assumption.

As in the WAPP Master Plan, the decided projects are commissioned at fixed dates while the candidate projects are regarded as investment options from 2014 for the thermal projects, and from 2018 for the hydro power projects. An option to import electricity from Central African region is not included in the WAPP Master Plan thus not included in our Reference Scenario either.

A Renewable Energy Policy Scenario (Renewable Scenario) was set up in which cost reductions for renewable energy technologies due to anticipated technology learning, consistent with the past trends (IRENA, 2013a), are taken into account. This is in contrast to the assumption adopted in the WAPP Master Plan's reference scenario, to which our Reference Scenario was calibrated. Fossil fuel prices are assumed escalated in contrast to the Reference Scenario. An option to import electricity from Central African region where vast hydro resource (such as Grand Inga) is included in all but one scenario.

Two variations of the Renewable Scenario were also defined:

» No Central Africa Import Scenario: Electricity import options from the Central African region are excluded.

» Energy Security Scenario: Import share is limited to 25% of the total electricity demand for each country. Countries that already have a higher than 25% share of electricity imports are modelled so that by 2030, the share is gradually reduced to 25%.

Throughout the analysis, conservative views on the resource potential, firm capacity of intermittent renewable source and penetration limits are retained to ensure that the resulting energy system is reliable. This is a short-cut representation of system reliability, and in the next round of the model improvement, the representation of system reliability would be enhanced by refining the firm capacity of intermittent renewable source according to the geographical dispersion of resource within a country, adding system integration costs of renewables, refining assessment of exclusion zones in solar and wind resource potential estimate, and conducting sensitivity analysis on the hydro generation. Representing the system reliability in the presence of a large share of renewables in energy system models is an on-going research topic elsewhere in the world. IRENA is keeping up with the latest methodological improvements, and trying to implement them wherever possible given the current modelling platform.

3.2 OVERALL ASSUMPTIONS

Overall assumptions across all scenarios are as follows:

» The real discount rate applied is 10%, consistent with the assumption in the WAPP Master Plan.

- The monetary unit used throughout is the 2010 USD rate and adjustments to reported data in USD from other years are made using the gross domestic product (GDP) inflator for the USA from the World Bank (WB, 2011).
- The study horizon spans from 2010 to 2050, with a focus on 2010 – 2030.
- In order to capture the key features of electricity demand load pattern, the year is characterised by three seasons, namely pre-summer (January – April), summer (May – August), and post-summer (September – December). Pre-summer and summer days are characterised by three blocks of equal demand, namely day (6AM-6PM), evening (6PM – 11 PM) and night (11 PM – 6 AM). Post-summer days are characterised with an additional block (7 PM) to capture the peak seen by the system.
- Penetration of intermittent renewables upstream of the transmission grid energy is limited to 10% of the total generation upstream of transmission for solar and 20% for wind, in order to conservatively ensure the system stability.

3.3 ASSUMPTIONS ABOUT ELECTRICITY DEMAND

The main source used for electricity demand projections is the WAPP Master Plan: Update of the ECOWAS Revised Master Plan for the Generation and Transmission of Electrical Energy (WAPP, 2011). The report provides secondary electricity demand projection to 2025 that is upstream of transmission, in some cases with mining projects handled separately. The demand projections considered in the Reference Scenario include the mining projects. Post-2025 demand is simply extrapolated from the growth projected by the ECOWAS study for the period 2020-2025. Figure 2 shows the evolution of the secondary electricity demand, which is dominated by Nigeria.

Projections for Guinea Bissau, Guinea, Sierra Leone and Liberia include electricity demand for mining projects that are projected to be several times larger than the other demands. There are possibly other mining projects in the West African region that were not identified in the WAPP Master Plan, such as gold mining in Burkina Faso, but these are also not included in this analysis.

The each country's secondary electricity demand was further divided into "heavy industry", "urban", and "rural" categories as follows:

- Heavy industry (e.g., mining), which connects to generation at a high voltage, and generally requires less transmission and no distribution infrastructure;
- Urban residential, commercial and small industries, which are connected to generation via relatively more transmission and distribution infrastructure; and
- Rural residential and commercial, which require even more transmission and distribution infrastructure.

A detailed bottom-up analysis is required to calculate the sectorial demand, but is beyond the scope of this work.

A simple and basic approach was adopted, which can be described as:

- The WAPP Master Plan projections at the utility (secondary) level became the baseline for the electricity demand projections.
- The subsequent energy balances were then used to split the base-year consumption into "heavy industry" and "other", with adjustments made for differences in loss, assuming that heavy industry has lower losses.
- The evolution of the split in the base-year consumption over time was roughly estimated, assuming that a small share of the electricity demand originated from rural areas.
- In some countries, the WAPP Master Plan explicitly provided the electricity demand for certain mining or industrial projects. For these countries, this additional demand was completely allocated to "heavy industry" with the remaining demand allocated to "urban" and "rural" sectors.

Each demand segment is characterised by a different load profile that is assumed to be common to all the countries. The load profile for each demand segment is defined by shares of demand in each season (pre-summer, summer, and post-summer) and shares of demand in each day-block (day, evening, night). Since different countries have different shares of these three segments, the resulting load profiles for total demand are specific to each country and evolve over time. The load shape data for Ghana in 2012 is shown in Figure 4 as an example.

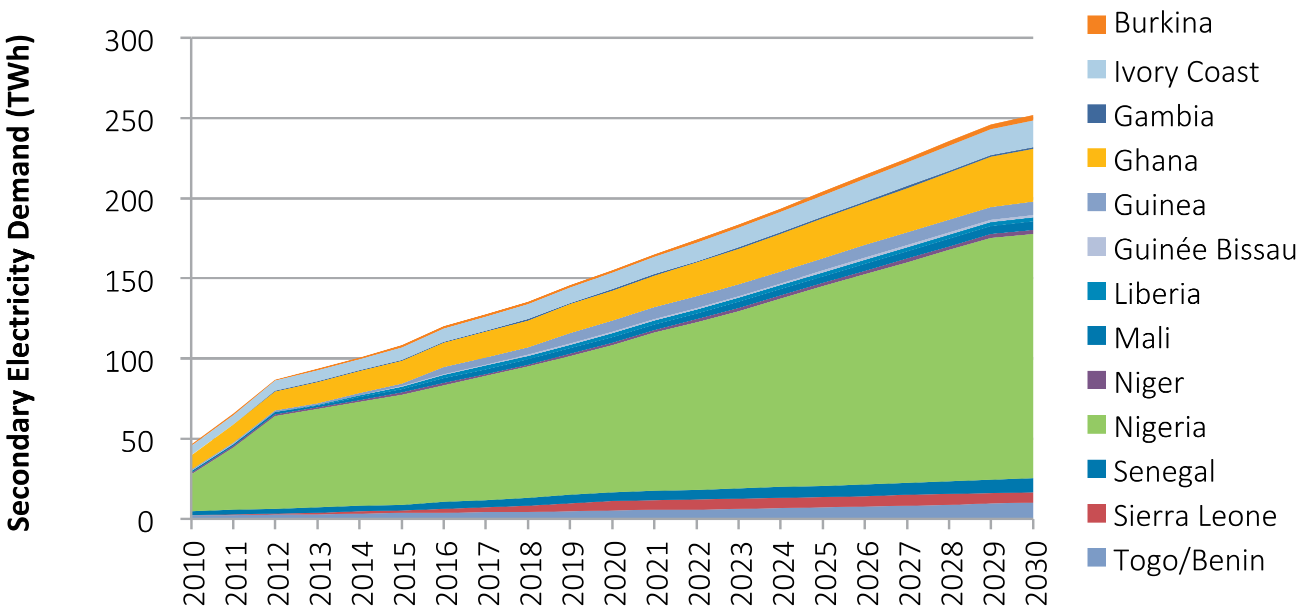

Figure 2. Secondary Electricity Demand Projections with Mining Projects

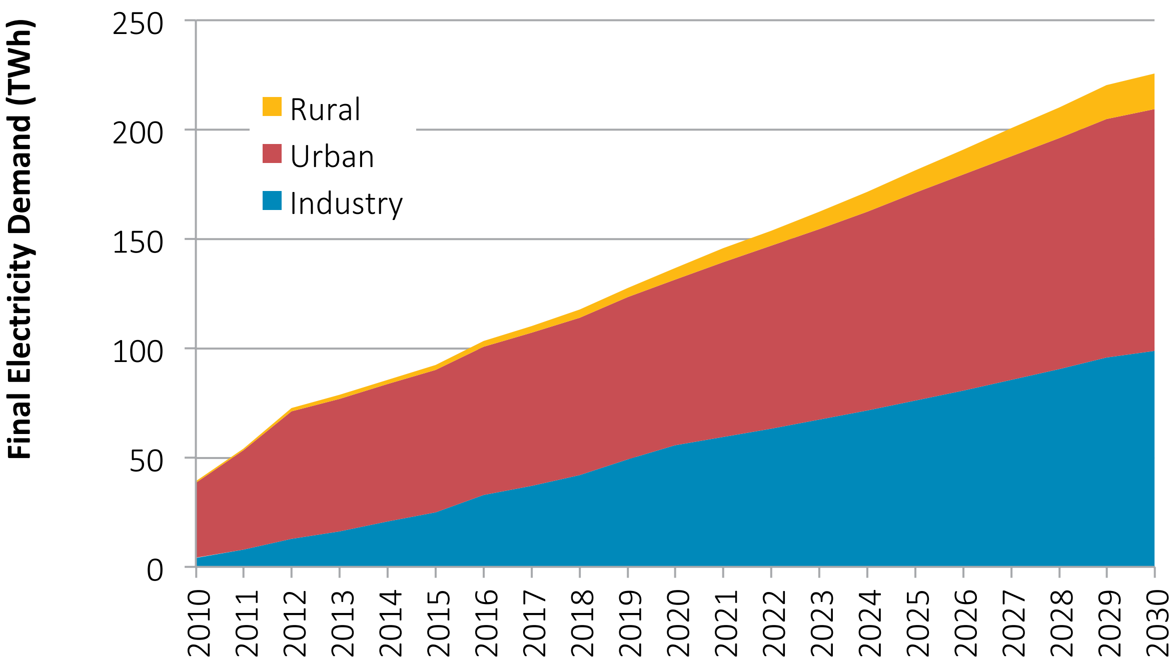

Figure 3. Total Final Electricity Demand by Sector

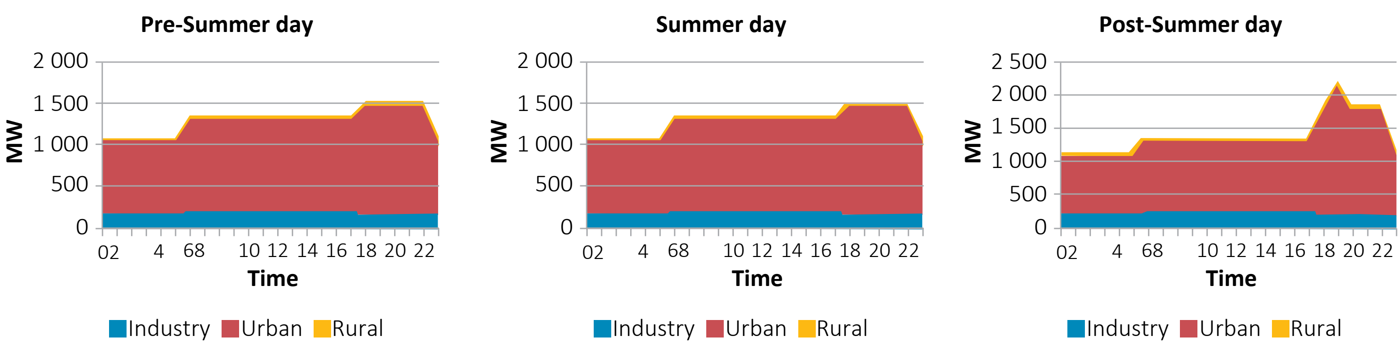

Figure 4. Load Shape Data – Ghana in 2012

3.4 ASSUMPTIONS ON LOCAL TRANSMISSION AND DISTRIBUTION

Transmission and distribution (T&D) infrastructure need to be invested to match the peak system demand (upstream of T&D, i.e., grid-connected system peak not including demand met by the off-grid-technologies). The needs for T&D infrastructure is modelled to match the peak system demand with some margin, which in turn aligns with installed capacity. Three different levels of cost and losses are defined for the three identified customer groups to account for the different levels of transmission and distribution infrastructure required. Off-grid technologies do not require transmission and distribution infrastructure, therefore no costs and losses are associated with it. The distribution requirement for mini-grid solution was ignored for the sake of simplification.

T&D infrastructure costs are assumed lowest to heavy industry, medium to urban customer group, and the highest to rural customer group (Table 1) and kept constant overtime. The assumptions on T&D losses are specific to each country. For industry, losses are assumed 7% for 2010, and are reduced to 5% by 2030. For urban customer group, they are assumed 17-30% for 2010 and are reduced to 13% by 2030 in all countries. The losses are highest to the rural consumer group, 20-35% for 2010 and are reduced to 25% by 2030 in all countries. The losses by country and by demand category are given in Appendix D. The T&D losses shown in Table 1 corresponds to the generic value used to calculate the levelised cost of electricity (LCOE) which are further discussed in Section 3.7 and Table 9.

3.5 ASSUMPTIONS ABOUT RENEWABLE RESOURCE POTENTIAL

Large Hydro

The large-hydro potential is limited to the identified hydro sites in the WAPP Master Plan (WAPP, 2011) and is summarised in Table 2. A "dry-year" scenario is assumed for all hydro sites in all years within the modelling horizon. This underplays the role of hydro in the region and is considered conservative in view of the vulnerability of West Africa to drought years. A more comprehensive stochastic approach (as used in WAPP 2011) was not possible due to limitations of the MESSAGE modelling platform. Detailed parameters for existing and planned hydro projects are given in Table 15, Table 16 and Table 17 in Appendix B.

Other Renewable Energy Potential

Estimates for the non-large-hydro renewable resource potential are shown in Table 3. Estimates for solar are based on the Mines ParisTech[3] dataset and wind data are based on the Vortex data set (9 kilometre (km) resolution) as reported by IRENA, (2013b). Although this estimate may underestimate the potential, given that it only considers 1% and 0.25% of suitable land area as being available for solar and wind generation respectively, the potential is so vast that none of the countries are expected to hit the resource constraints by 2030[4]. The mini-hydro data are based on United Nations Industrial Development Organisation (UNIDO)/ ECOWAS Regional Centre for Renewable Energy and Energy Efficiency (ECREEE) (2010) and the biomass data are based on IRENA (2011b).

3.6 ASSUMPTIONS ABOUT FUEL AVAILABILITY AND PRICES

Three types of gas are assumed available for supply: locally produced gas (in Nigeria, Cote d'Ivoire, and Ghana); Nigerian gas, supplied through the Western African Gas Pipeline (in Ghana, Togo, and Benin); and imported liquefied natural gas, LNG (other coastal countries).

For petroleum products, three types of fuel are distinguished: heavy fuel oil (HFO), distillate diesel oil (DDO), and light crude oil (LCO). Different prices are assumed for the petroleum products delivered to coastal countries and inland countries.

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[1] Note that the costs of the distribution technologies are modelled as investment cost based on the load factor of each of the demand categories and not as a variable cost, i.e,. the table shows the levelised cost of distribution.

[2] In Nigeria there is 3,300 MW of identified hydro projects. The rest is based on REMP (2005), which identified a total potential of 11,500 MW of large hydro for Nigeria.

[3] HelioClim-3, developed by Mines ParisTech and operated by Transvalor, is a satellite-based database with a long history, where data and maps are offered via the SoDa online portal. Read more at: www.pv-magazine.com/archive/articles/beitrag/solar-resource-mapping-in-africa-_100009438/501/#ixzz2JNDgfV6q

[4] Solar potential would correspond to 2-100 times larger than the projected total electricity demand in respective countries in 2030, and for solar only 3% of the potential would be utilised in the Renewable Scenario presented below.

Table 1. Assumptions for Transmission and Distribution Infrastructure Costs[1] and Losses

	Cost (USD/kWh)	Losses (%)		
		2010	2020	2030
Heavy Industry	0.015	7	7	5
Urban Residential/Commercial/ Small Industries	0.05	20	15	13
Rural Residential/Commercial	0.10	30	25	25

Table 2. Existing Hydro and Identified Hydro Projects

	Existing Hydro			Identified Hydro Projects		
Country	**Capacity**	**Average Generation**	**Dry-Year Generation**	**Capacity**	**Average Generation**	**Dry-Year Generation**
	MW	GWh	GWh	MW	GWh	GWh
Burkina Faso	23	91	41	60	192	146
Cote d'Ivoire	585	2,424	1,842	1,072	4,953	2,916
Gambia	0	0	0	68	241	92
Ghana	1,044	5,051	3,722	661	2,330	1,010
Guinea	95	482	379	3,346	14,296	10,974
Guinea-Bissau	0	0	0	14	48	18
Liberia	0	0	0	967	4,763	3,633
Mali	153	683	495	434	2,003	1,342
Niger	0	0	0	279	1,269	486
Nigeria [2]	1,358	7,476	4,632	10,142	43,710	33,220
Senegal	68	264	165	530	1,988	1,100
Sierra Leone	56	321	158	755	4,168	3,468
Togo/Benin	65	173	91	357	1,004	722
Total	**3,447**	**16,965**	**11,525**	**18,682**	**80,964**	**59,129**

Table 3. Non-Large-Hydro Renewable Energy Potential Rough Estimates

Country	**Mini Hydro**	**Solar CSP**	**Solar PV**	**Biomass**	**Wind 20%**	**Wind 30%**
	MW	TWh	TWh	MW	MW	MW
Burkina Faso	140	18.1	77.4	2,250	4,742	29
Cote d'Ivoire	242	2.2	103	1,530	491	0.0
Gambia	12	3.2	4.74	23.75	197	5
Ghana	1	2.3	76.4	1,133	691	9
Guinea	332	4.7	52.0	656	2.4	0
Guinea-Bissau	2	9.0	14.9	71	142	0
Liberia	1,000	0.0	6.67	459	0	0
Mali	67	36.2	79.1	1,031	2,195	0
Niger	50	88.3	157	1 115	16,698	5,015
Nigeria	3,500	100	325	10,000	14,689	363
Senegal	104	15.4	75.2	475	6,226	1,243
Sierra Leone	85	2.0	15.0	166	0.0	0
Togo/Benin	336	0.0	51.6	957	551	0

For coal, only Nigeria and Niger are assumed to have resources for local production, all other coastal countries have the option of coal imports that are assumed to be available. Inland countries other than Niger are assumed to have no domestic coal resource or coal transport infrastructure, and costs to these countries are assumed to be prohibitively expensive.

For biomass, two types of biomass are distinguished: moderately priced biomass and relatively expensive biomass in countries where biomass resource is scarce. Countries where the agriculture industry could potentially make biomass available to the power sector were allocated to the moderate category and resources in the three inland countries of Burkina Faso, Niger and Mali are assumed to be scarce.

The assumptions on fuel availability are summarised in Table 4.

Base-year fossil fuel prices are based on the WAPP Master Plan (WAPP 2011). The fuel prices for gas, oil products and coal in the base year in the Master Plan were derived from an assumption of OPEC oil price being USD 100 per barrel. In the Reference Scenario, the fossil price is kept constant throughout the study period, following the assumption adopted in the WAPP Master Plan. In the Renewable Scenario and its variations, it is assumed that future prices for oil products increase 20% by 2020 and 35% by 2030, compared to the base year. For gas prices, the escalation relative to 2010 value in 2020 and 2030 is 10% and 30% respectively. The domestic coal in Niger and Nigeria is set at a lower price compared to the landed price in coastal countries. The domestic coal price was based on Idrissa (2004). It is not clear in the WAPP Master Plan whether it distinguishes between the price for locally produced coal for Niger/Nigeria and imported coal for coastal countries.

The assumed price evolutions for fuels are summarised in Table 5.

Dennis Schroeder©SolarTAC test facility in Aurora, CO/NREL

Table 4. Assumptions on Fuel Availability

Country	Coal	Gas	Oil	Biomass
Burkina Faso	NA	NA	Inland	Scarce
Cote d'Ivoire	Import	Domestic	Coastal	Moderate
Gambia	Import	LNG	Coastal	Moderate
Ghana	Import	Domestic/Pipeline	Coastal	Moderate
Guinea	Import	LNG	Coastal	Moderate
Guinea-Bissau	Import	LNG	Coastal	Moderate
Liberia	Import	LNG	Coastal	Moderate
Mali	NA	NA	Inland	Scarce
Niger	Domestic	NA	Inland	Scarce
Nigeria	Domestic	Domestic	Coastal	Moderate
Senegal	Import	LNG	Coastal	Moderate
Sierra Leone	Import	LNG	Coastal	Moderate
Togo/Benin	Import	Pipeline	Coastal	Moderate

Table 5. Fuel Price Projections

USD/GJ	2010	2020*	2030*
HFO (delivered to the coast)	12.9	15.5	17.4
HFO (delivered to the inland)	16.3	19.6	22.0
Diesel (delivered to the coast)	21.9	26.3	29.6
Diesel (delivered to the inland)	25.2	30.2	34.0
LCO (delivered to the coast)	17.8	21.4	24.0
LCO (delivered to the inland)	18.9	22.7	25.5
Gas Domestic	8.5	9.5	11
Gas Pipeline	10.3	11.4	13.5
Gas Imported (LNG)	11.0	12.3	14.2
Coal Domestic	3.0	3.3	3.5
Coal Imported	4.6	5.0	5.3
Biomass Free (Sugar Cane)	0.0	0.0	0.0
Biomass Not Free	1.5	1.5	1.5
Biomass Scarce	3.6	3.6	3.6

*For the fossil fuels, prices in 2020 and 2030 are kept constant as in 2010 in the Reference Scenario.

3.7 ASSUMPTIONS ABOUT ELECTRICITY GENERATION OPTIONS

Existing Generating Capacity

Existing thermal and hydro generation is based on WAPP (2011) and is summarised in Table 6. Detailed parameters are given in Table 14 and Table 15 in Appendix B.

Future Power Generation Options

There are two types of future technology options: site-specific projects and generic technology options. Site specific projects are taken from the WAPP Master Plan and they are specified with unit size, capacity factor, efficiency, O&M costs, investment costs, etc. Some of them are already "committed" and thus are forced to be a part of future energy mix. Other projects are just "under consideration", and they may or not be included in the "optimal solution" computed by the model under a set of scenario assumptions for the respective scenarios. Similarly, generic technology options may or not be in the "optimal solution".

Table 7 shows the summary of power generation projects as per WAPP (2011). Detailed tables are given in Table 16 and Table 17 in Appendix B.

In the EREP model, the demand is first met by existing technologies and committed projects. The reminder of the demand is met by site-specific projects and/or generic power generation technologies. The generic power generation technologies are modelled without a specific reference to any unit size. Certain technologies are assumed to provide electricity only via the grid, while others are assumed to provide on-site electricity.

For thermal technologies, the following options are included as generic technologies:

» Diesel/Gasoline 1 kW system to supply the urban and rural demand

» Diesel 100 kW system to supply the industry demand

» Diesel Centralised connected to the upstream of transmission

» Heavy Fuel Oil connected to the upstream of transmission

» Open Cycle Gas turbine (OCGT) connected to the upstream of transmission

» Combined Cycle Gas Turbine (CCGT) connected to the upstream of transmission

» Supercritical coal connected to the upstream of transmission

For renewable energy technologies, the following options are included as generic technologies:

» Small or mini-hydro to supply rural demand.

» On-shore wind connected upstream of transmission. Two wind regimes are considered, one where the capacity factor is 30%, and the other where the capacity factor is 20%.

» Biomass mainly in the form of co-generation to be consumed on-site with surplus exported onto the grid (upstream of transmission).

» Utility PV or PV farms managed by the utility and connected upstream of transmission. These were modelled to only produce electricity during the day.

» Distributed or rooftop solar PV to supply either urban residential, commercial and small industries, or rural residential and commercial. These were modelled to only produce electricity during the day.

» Distributed or rooftop solar PV with 1 hour of storage in the form of a battery, for slightly extended use beyond daylight hours.

» Distributed or rooftop solar PV with 2 hours of storage in the form of a battery, more extended use beyond daylight hours.

» Solar CSP no storage medium to large-scale concentrated solar connected upstream of transmission.

» Solar CSP with storage medium to large-scale concentrated solar with thermal storage. This can supply electricity during the day and in the evening.

Note that for hydropower technologies, given the lengthy project lead time only the site-specific technologies are included as future generation options, with the exception of Nigeria[5].

Cost of Future Power Generation Options

Table 8 shows the assumptions on overnight investment costs for generic (i.e., non-site specific) power generation

[5] For Nigeria, generic hydro options are included after 2030. For other countries, data on total hydro resource were not available.

Table 6. Existing Generating Capacity (MW)

Country	Oil	Coal	Gas	Hydro	Total
Burkina Faso	146			23	**169**
Cote d'Ivoire			765	585	**1,350**
Gambia	49			0	**49**
Ghana	685		180	1,044	**1,909**
Guinea	19			95	**114**
Guinea-Bissau	4			0	**4**
Liberia	13			0	**13**
Mali	114		20	153	**287**
Niger	15	32	20	0	**67**
Nigeria			3,858	1,358	**5,216**
Senegal	395		49	68	**512**
Sierra Leone	44			56	**100**
Togo/Benin	57			65	**122**
Total	**1,541**	**32**	**4,892**	**3,447**	**9,912**

Table 7. Summary of Future Projects (in parenthesis, sum of committed projects)

MW	Oil	Coal	Gas	Hydro	Biomass	Wind	Solar	Total
Burkina Faso	120 (112)	-	-	60	-	-	40	220 (112)
Cote d'Ivoire	-	-	1,313 (863)	1,072	-	-	-	2,385 (863)
Gambia	16 (16)	-	-	68	-	1 (1)	-	85 (17)
Ghana	100	-	2,265 (1 180)	661 (228)	-	150 (150)	10 (10)	3,186 (1 568)
Guinea	227 (227)	-	-	3,346 (287)	-	-	-	3,573 (514)
Guinea-Bissau	15 (15)	-	-	14	-	-	-	29 (15)
Liberia	45 (45)	-	-	967 (66)	35	-	-	1,047 (111)
Mali	332 (166)	-	-	434 (90)	33	-	40 (10)	839 (266)
Niger	32 (15)	200	18 (8)	279 (98)	-	30	50	609 (121)
Nigeria	-	-	13,581 (8,531)	3,300	-	-	-	16,881 (8 531)
Senegal	540 (180)	1,000 (250)	-	530	30 (30)	225	8	2,333 (460)
Sierra Leone	-	-	-	755	115	-	5	875
Togo/Benin	-	-	630 (580)	357 (147)	-	20	35	1,042 (727)
Total	1,437 (776)	1,200 (250)	17,807 (11,162)	11,840 (916)	213 (30)	426 (151)	188 (20)	33,104 (13 305)

technologies in the base year. For non-renewable technologies, they are mainly based on the WAPP Master Plan, except for distributed diesel generators where parameters are sourced from the ESMAP 2007 study on distributed generators. No technology learning, which leads to cost reduction, is assumed in all scenarios throughout the study period for this type of technologies.

For renewable technologies, reduction of overnight investment cost was assumed in the Renewable Scenario. The assumption is graphically presented in Figure 5. The learning rates anticipated are based on increased global installed capacity in those technologies. What is assumed here is more aggressive reduction of costs, assuming that these are achieved as a result of governments and the private sector in the region actively seeking opportunities for raised local content, increased streamlining of regulations and taxation regimes, resolved bottlenecks in materials supply (including transportation problems and logistical constraints), economies of scale, economic efficiency gains and so forth.

Assumptions on load factor, O&M costs, efficiency, construction duration and expected technology life for all the generic technologies are given in Table 18 in Appendix C. They are kept identical in all scenarios.

Levelised Costs of Generic Technologies

We calculated levelised costs of electricity (LCOE) for generic technology options based on the current and projected investment costs, fuel costs, operation and maintenance costs, capacity factor, generation capacity, and expected years of operation, all in the context of Africa.

Based on the above assumptions on investment costs, operation and maintenance costs, fuel prices, operation and maintenance costs, capacity factor, generation capacity, and expected years of operation, a levelised cost of electricity (LCOE) was computed for generic technology options available to the countries in the region. For delivery of electricity using grids to different customer group, additional transmission and distribution (T&D) costs are added while taking into account the T&D losses, which are detailed in Table 1 for the industrial, urban, and rural customer groups[6].

LCOEs of generic technologies considered in this analysis were computed for 2010, 2020, and 2030 based on assumptions for respective years under the Renewable Scenario. The LCOEs plus T&D costs were also computed for three customer groups. They are presented in Table 9 for 2010 and 2030. A more complete LCOE summary is given in Table 19 through Table 21 in Appendix C.

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[6] LCOE for the industry customer = LCOE of generation / (1-loss) + T&DTD costs of industry. For example, for diesel centralised, LCOE for the industry customer is: 291/(1-0.07)+15=328.

Table 8. Assumptions on Overnight Investment Costs for Generic Power Technologies

Overnight Costs	
	USD/kW
Diesel/Gasoline 1 kW system (urban/rural)	692
Diesel 100 kW system (industry)	659
Diesel Centralised	1,070
HFO	1,350
OCGT	603
CCGT	1,069
Supercritical coal	2,403
Hydro	2,000
Small hydro	4,000
Biomass	2,500
Bulk wind (20% CF)	2,000
Bulk wind (30% CF)	2,000
Solar PV (utility)	2,000
Solar PV 1 kW1kW (rooftop)	2,100
PV with battery (1 hour storage)	4,258
PV with battery (2 hour storage)	6,275
Solar CSP no storage	3,000
Solar CSP with storage	5,400
Solar CSP with gas co-firing	1,388

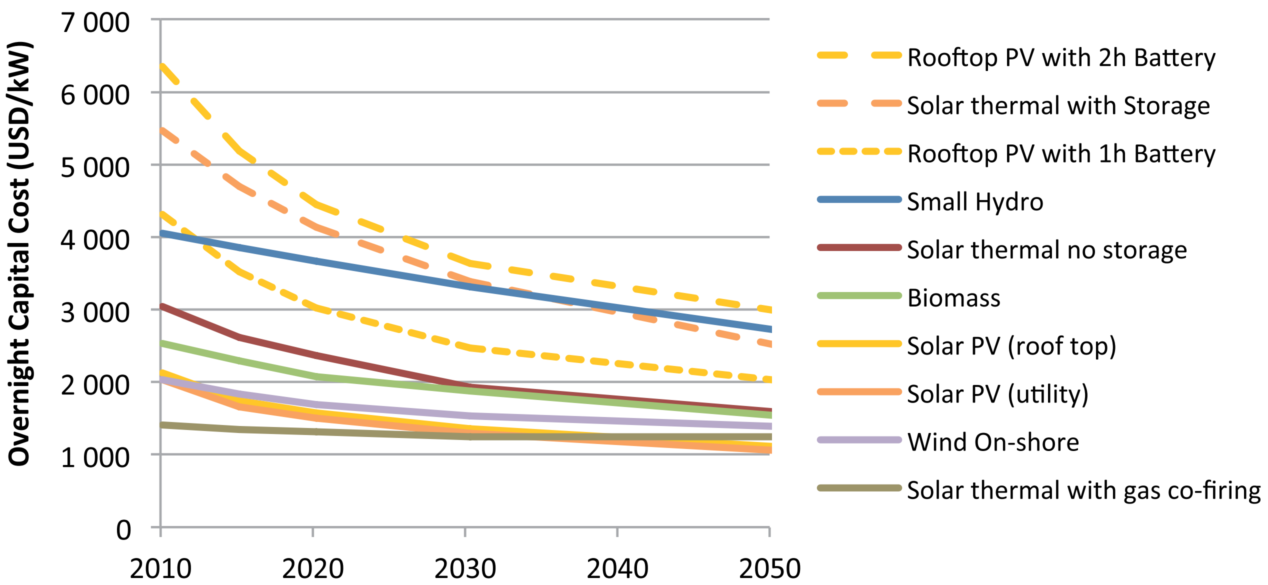

Figure 5. Overnight Investment Cost for Renewable Energy Technologies (in Renewable Scenario) (Units: USD per kilowatt)


Thorsten Schier©High voltage power lines with electricity pylons at twilight/Shutterstock

The LCOE table shows that for industrial customers connecting at high voltage, hydro is the cheapest option, followed by CCGTs using domestic gas and for countries that have domestic coal, coal generation is the next cheapest option. CCGT with imported gas is initially the next best option, but is overtaken by high-capacity factor wind as its investment cost comes down and the gas price goes up in 2020. Electricity from imported coal is the subsequent best option, but this also changes by 2020 and 2030, with wind again becoming more cost-effective. Biomass, where available, is then the next cheapest option. Initially, solar CSP with gas co-firing is interesting, but this option gets overtaken by PV and solar thermal without storage, as the CSP price is expected to go up. PV utility and solar CSP are the next best options for countries without any other domestic resources of gas, coal, wind or biomass.

For rural customers, mini-hydro remains the best option, where it is available. Distributed/rooftop PV with and without batteries is expected to become the next best option for these customers in the Renewable Scenario.
The LCOE results shown here assume a load factor equal to the availability of the technologies. Given differences in investment and fuel costs, the ranking would change at different load factors. For example, gas plants at an 80% load factor may be less competitive than coal on a levelised basis, but more competitive at 40%. Diesel or open cycle gas turbines (OCGTs) would be competitive at very low load factors and may well play a role in meeting peak loads, which occur for short durations. The MESSAGE model takes account of this in the optimisation, which is one of the reasons why the results of the optimisation may differ from what could be expected given the simple LCOE analysis.

Note that for hydro power, generic technology options and generic costs were not used in the model, although a typical LCOE of hydro power options is shown in this LCOE table as a reference of the cost competitiveness of the hydro options. Actual distribution of LCOE of 63 hydro projects included in the model as future options is shown in Figure 6. Since the costs are highly site-dependent, the variability of costs is quite high.

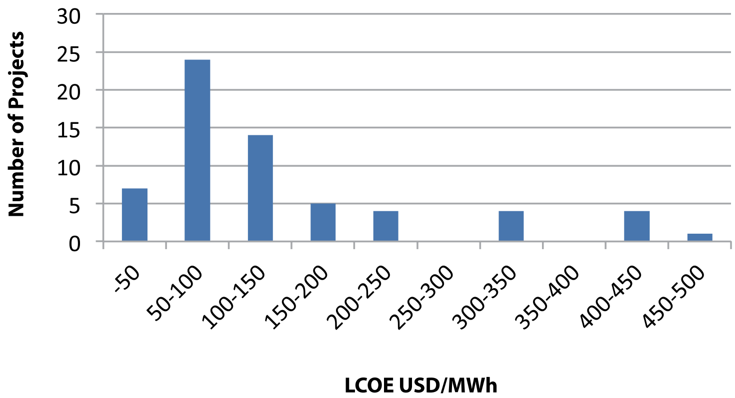

Figure 6. Distribution of the LCOE of the 63 Hydro Projects

Table 9. Levelised Cost of Electricity: Assumptions

LCOE (USD/MWh)	Generation		Industry		Urban		Rural	
	2010	2030	2010	2030	2010	2030	2010	2030
Diesel centralised	291	339	328	372	414	440	516	552
Dist. diesel 100 kW	320	371	320	371				
Dist. diesel/gasoline 1 kW	604	740			604	740	604	740
HFO	188	216	217	243	285	299	369	389
OCGT (imported gas/LNG)	141	161	167	185	226	235	301	315
CCGT (imported gas/LNG)	90	102	112	123	162	167	229	236
CCGT (domestic gas)	90	102	112	123	162	167	229	236
Supercritical coal	101	106	124	126	176	172	244	241
Supercritical domestic coal	81	93	102	113	151	157	216	224
Hydro	62	62	82	80	128	122	189	183
Small hydro	107	89					107	89
Biomass	104	86	127	106	181	149	249	215
Bulk wind (20% CF)	149	106	176	138	237	184	314	256
Bulk wind (30% CF)	102	73	125	100	178	143	246	208
Solar PV (utility)	121	84	145	103	201	146	272	212
Solar PV 1 kW (rooftop)	143	96			152	105	152	105
PV with battery (1 hour storage)	250	151			250	151	250	151
PV with battery (2 hour storage)	323	192			163	110	163	110
Solar CSP no storage	147	102	173	122	234	167	311	236
Solar CSP with storage	177	116	205	137	271	184	352	255
Solar CSP with gas cofiring	106	115	129	136	183	182	251	253

3.8 ASSUMPTIONS ON TRADE BETWEEN COUNTRIES

Trade between countries is limited by existing infrastructure and planned transmission projects. Any hypothetical projects that are not currently identified are not included as options. Existing transmission infrastructure and planned projects for transmission are based on the WAPP Master Plan (WAPP, 2011) and are summarised in Table 10 and in Table 11, with details in and Table 22 and Table 23 in the appendices. In the case of "import restriction scenario", 25% of import in the total electricity demand is set to be a limit.

3.9 CONSTRAINTS RELATED TO SYSTEM AND UNIT OPERATION

In the EREP model, key system constraints are introduced to make sure the system is reliably operated.

Reserve Margin

In order to increase the reliability of a power system, excess "operational" capacity needs to be installed over and above peak demand requirements.

A reserve margin is defined as the difference between operable capacity and the peak demand for a particular year as a percentage of peak demand. In all scenarios, a reserve margin constraint of 10% has been imposed on countries. Only "firm" capacity, which is guaranteed to be available at a given time, is considered to contribute to this requirement. The capacity credit, which is a share of capacity that is considered firm, is set to 1 for dispatch-able technologies such as thermal and large hydro with dams. For intermittent renewable power technologies, however, the capacity credit depends on the share of total capacity and the quality of the intermittent resource in terms of the diversity of sites with low correlation, and is generally lower than the availability factor as they cannot be relied to generate power at an any given desired time due to the variability of the wind and solar conditions.

The reserve margin constraint is defined as follows:

$$\sum_{i=1}^{n} \alpha(i) C_P(i) \geq (1 + RM)D$$

Where:

» *α(i)* is the capacity credit given to power plant/technology *(i)* or share of capacity that is accounted as "firm" (fraction);

» $C_p(i)$ is the capacity of power plant/technology *(i)* in MW (centralised only);

» *D* is the peak demand on the centralised grid system in MW; and

» *RM* is the reserve margin (fraction).

Constraints on Variable Renewables

Given that the model has an aggregate representation of the load, the variability of wind and solar PV was accounted for in an aggregate and conservative manner:

» The capacity of wind was de-rated by the availability factor (i.e., a 100 MW wind plant with 30% capacity factor is constrained to only deliver 30 MW at any given point in time). The firm capacity of every MW of installed capacity was set to half the availability factor (capacity credit = half availability, in this example, 15 MW).

» Centralised PV plants and CSP were given a 5% and 30% capacity credit respectively.

When the resources are spread over a large area, "firm capacity" may increase as the meteorological variability is dispersed and the generation is less effected by local meteorological conditions in a specific area. However, such consideration is not given under the current study, so an upper limit on the share of generated electricity in the grid coming from wind was set for all countries at 20% and 10% for centralised PV. This was set conservatively to ensure reliable systems are projected, until the methodology is improved to allow more sophisticated modelling of intermittent supply options.

Load following capability of power plants

There are some technical limitations as to how fast coal plants can ramp up or down production. Coal power plants and biomass power plants have limitation in this regard. To try and capture this limitation, all coal plants in the model were de-rated by (1-availability). For example, a 100 MW coal plant with an availability of 85% can only produce up to 85 MW at any given point in time. Biomass power plants were de-dated by the availability factor (50%).

Table 10. Existing Transmission Infrastructure Summary

Country 1	Country 2	Line Capacity
		MW
Ghana	Cote d'Ivoire	327
Ghana	Togo/Benin	310
Senegal	Mali	100
Cote d'Ivoire	Burkina	327
Nigeria	Togo/Benin	686
Nigeria	Niger	169

Table 11. New Cross-Border Transmission Projects

Project name	Approximate Line Capacity	Earliest year
	MW	
Committed projects		
Dorsale 330 kV (Ghana, Togo/Benin, Cote d'Ivoire)	650	2013
CLSG (Cote d'Ivoire, Liberia, Sierra Leone)	330	2014
OMVG (Senegal, Guinea, Gambia, Guinea Bissau)	315	2017
Hub Intrazonal (Ghana, Burkina Faso, Mali, Cote d'Ivoire, Guinea)	320	2014-2020
Planned projects		
Corridor Nord (Nigeria, Niger, Togo/Benin, Burkina Faso)	650	2014
Other projects		
Dorsale Mediane (Nigeria, Togo/Benin, Ghana)	650	2020
OMVS (Mali, Senegal)	330	2020

Warren Gretz©Harvesting corn and stover/NREL

Run-of-river hydro power plants as well as mini-hydro options are modelled as non-dispatchable, so also with the capacity de-rated by (1-availability). Hydro power plants with dams are modelled as dispatchable to reflect the more flexible operation that a dam allows. All hydro options are modelled with the "dry-year" assumption for availability.

Finally, the modelled dispatch patterns of three types of solar rooftop PV system are illustrated in Figure 7 (showing here the output of 1 MW of installed rooftop PV).

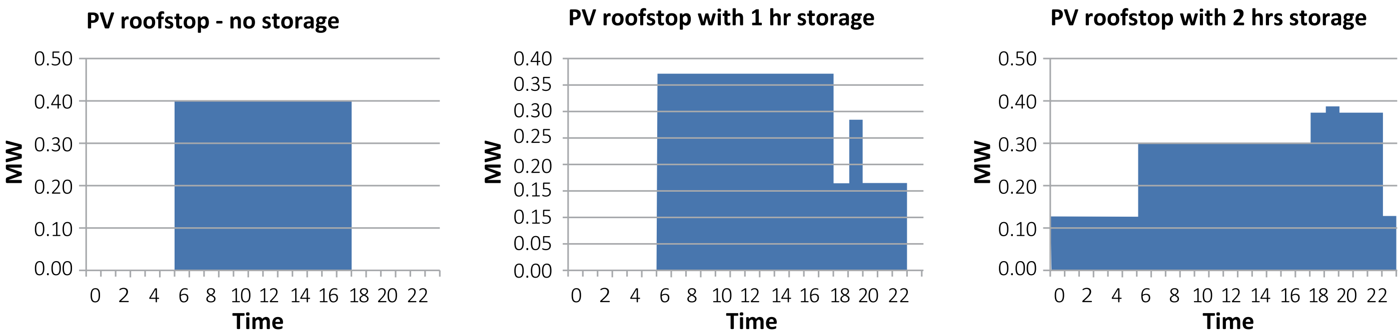

Figure 7. Diurnal variation of Solar PV output

4. Modelling Results

4.1 REFERENCE SCENARIO

The Reference Scenario is calibrated to the reference scenario of the WAPP Master Plan, which is based on a number of conservative assumptions on renewable deployment. This study's Reference Scenario was set up mainly to demonstrate the compatibility of the tool used for the WAPP Master Plan development.

As expected, the results are consistent with those presented in the reference scenario of the WAPP Master Plan. Figure 8 presents the electricity generation mix in the Reference Scenario.

The main difference between the EREP results and the WAPP Master Plan is the lower share of hydro in the EREP model due to the "dry-year" assumption imposed over the entire modelling horizon.

It is worth noting that EREP filled current supply-demand gap with on-site diesel generators. As more power supply options become available, this gap is quickly filled and replaced by grid-supply electricity or on-site renewable energy technology options, mainly from mini-hydro.

Hydropower share in the total electricity generation increases from 18% to 34% (22% to 29% of grid-connected electricity), and the share of other renewables remains small, at 5% by 2030 with most of it coming from biomass.

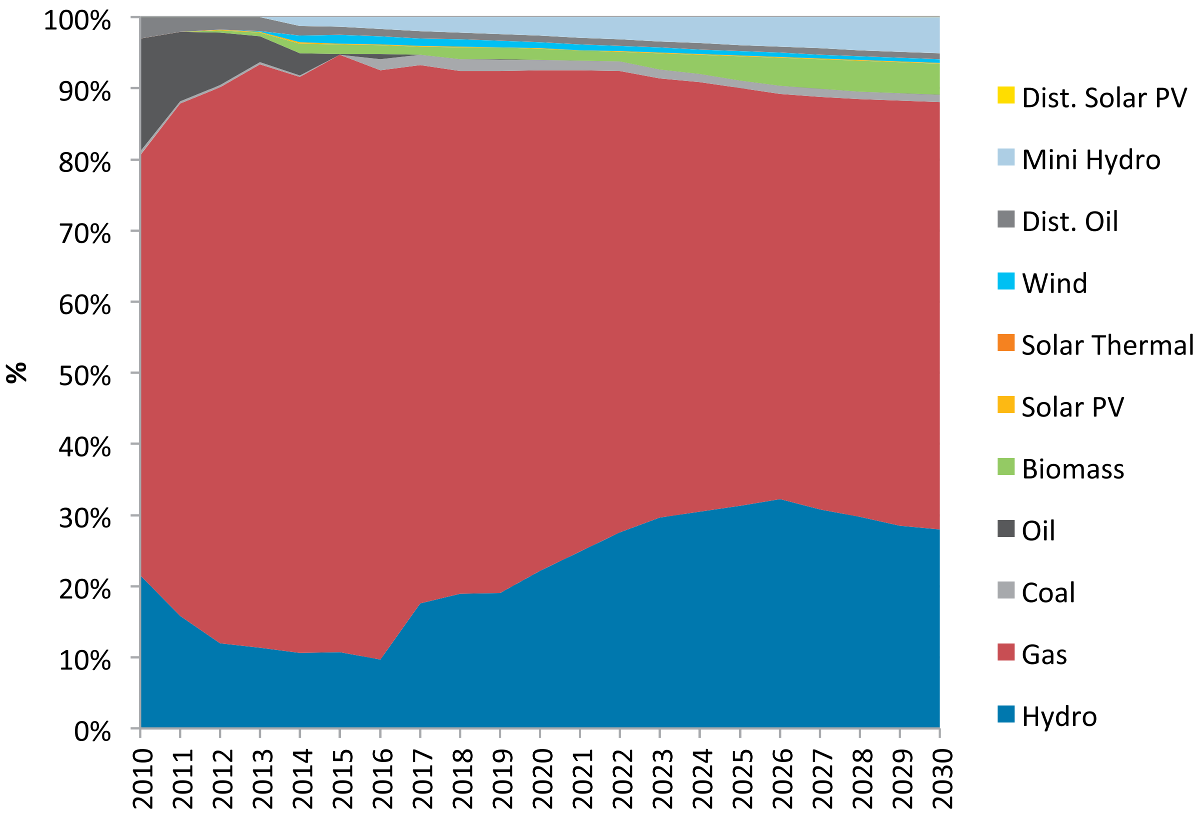

Figure 8. Electricity Production in the Reference Scenario

4.2 RENEWABLE SCENARIO: INVESTMENT AND GENERATION MIX THROUGH 2030

In the WAPP connected countries, electricity demand is expected to increase nearly six folds by 2020 and nearly 14 times by 2050. The installed grid connected capacity in 2010 is estimated to be about 9.4 GW, out of which more than half is fuelled with gas, 33% is hydro based, and the remainder is mainly fuelled with oil.

The current grid connected capacity is not sufficient to cover the current demand and we assessed that over 1GW of decentralised diesel generator is installed to meet the deficiency.

Figure 9 shows the retirement schedule of the existing capacity. By 2030, half the capacity will be retired. In order to meet the growing demand, additional capacity of over 60 GW would be needed under the Renewable Scenario.

Figure 10 shows the investment schedule under the Renewable Scenario. Appendix E shows all the project 'selected' in this scenario. In the first decade, 23 GW of gas would be deployed, out of which 11 GW is accounted by already committed projects. 16 GW of hydro would be deployed, nearly half of it in the first decade and the reminder in the second. Distributed diesel generators would continue to be deployed mainly in the heavy industry sector. Deployment of renewable technologies except large hydro would be over 13 GW by 2030.

Table 12 shows the capacity addition during 2010-2030 by countries, presented for centralised power generation capacity and decentralised power generation capacity. Out

Solar Panels in West Africa (ECREEE)

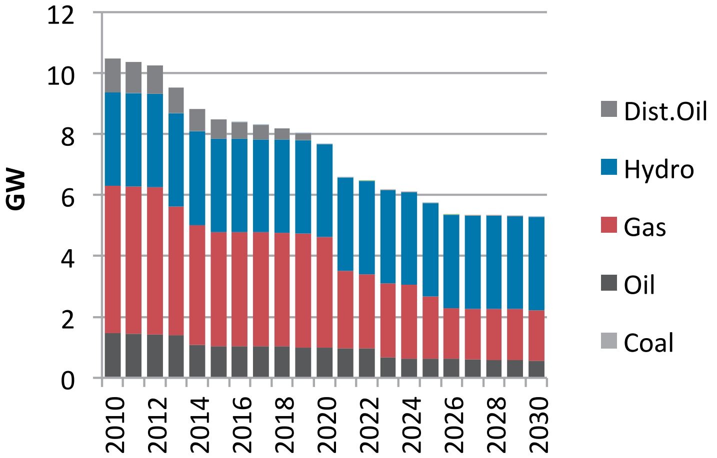

Figure 9. Capacity Balance of Existing Plans

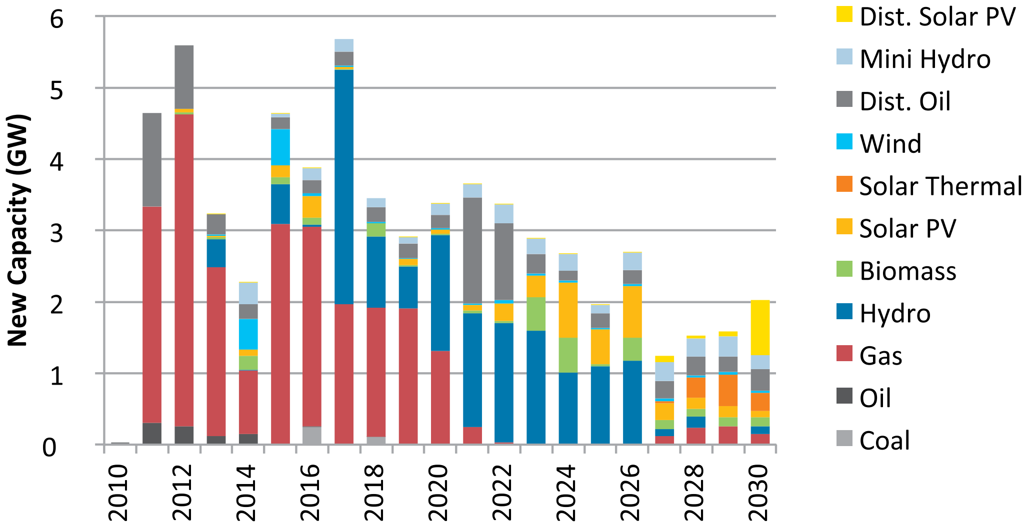

Figure 10. New Capacity (gross) Addition under the Renewable Scenario till 2030

Table 12. Capacity Addition during 2010-2030 by Country in MW

MW	Centralised		Decentralised	
	Total	Renewable	Total	Renewable
Burkina Faso	800	688	258	121
Cote d'Ivoire	3,543	962	702	152
Gambia	254	179	91	36
Ghana	5,182	2,928	2,177	896
Guinea	3,842	3,615	244	120
Guinea-Bissau	294	145	62	17
Liberia	560	402	78	46
Mali	890	682	162	72
Niger	645	469	130	47
Nigeria	29,057	10,504	7,506	2,568
Senegal	2,299	1,869	471	104
Sierra Leone	1,418	1,185	258	120
Togo/Benin	1,919	1,296	500	90
Total	**50,704**	**24,924**	**12,640**	**4,389**

of total capacity addition of 63 GW, renewable technology would account 46%

As a result of these new investments, the share of renewable in the total generation capacity would increase from 29% (only hydro) to 51% (30% hydro; 21% other). This goes beyond one of the ECOWAS renewable policy target, which defines the total renewable energy penetration by 2030 to be 48%. Figure 11 shows the development of capacity balance in the region under the Renewable Scenario.

The implication of these investments on the electricity supply mix under the Renewable Scenario is shown in Figure 12. Note that this figure includes electricity supply from Central Africa region (shown as Net import). The general trend is the replacement of gas based generation with more hydro and import.

Looking at the electricity supply mix in in 2030, the share of large hydropower increases from 22% to 28% (if accounting the import from Central Africa as hydro, the share becomes 41%), and other renewable would add 17%, which makes total share of renewable origin electricity in the total supply in 2030 would become 58%. In terms of the share of renewable in the generation mix (i.e., not taken into account the import), the share of renewable in the generation increases from 22% in 2010 to 52% (33% hydro; 19% remainder) in 2030.

The share of renewable energy generation in the grid connected generation is 48%, of which hydro alone accounts for 35% points. Compared with the ECOWAS Regional Renewable Policy, the regional target for the grid-connected renewable generation is 31% of grid-connected generation by 2030. Our renewable scenario is optimistic[7] and the ECOWAS Regional Renewable Policy target for the electricity sector would be achieved in early 2020s'.

Decentralised electricity supply options account for 7% of total electricity supply in2030, and major part of it is based on renewable sources.

The overall picture presented above is, to a large extent, dominated by developments in Nigeria and in Ghana, as they account for about 60% and 10% of the total regional electricity demand. Figure 13 shows generation mix in 2010 and 2030 in each country analysed under the Renewable Scenario. In 2010, electricity is produced mainly by gas, oil, or hydro. Some countries have excessively high import shares. In 2030, the means of electricity production would get diversified in all countries under this scenario.

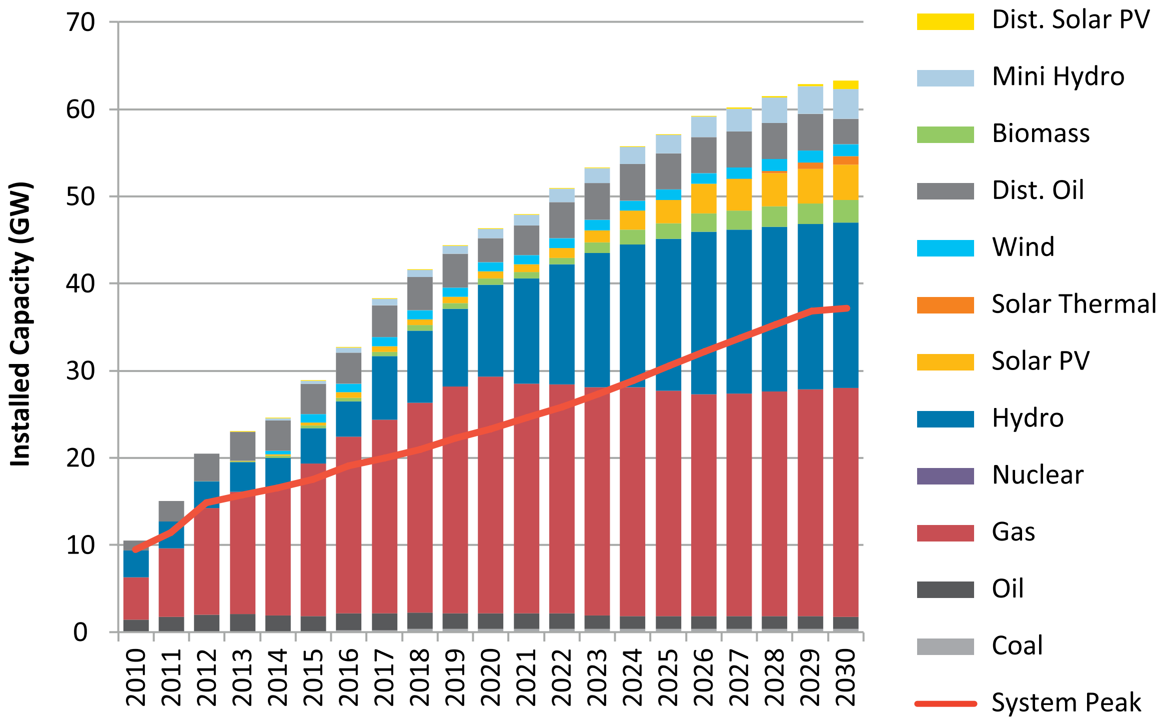

Figure 11. Capacity Balance under the Renewable Scenario

[7] When comparing our results against the ECOWAS Regional Renewable Policy in terms of the share of renewable based on the installed capacity by 2030, the difference was much smaller (51% in our scenario and 49% in the Policy). It is mainly explained by the fact that in our technology portfolio, we explicitly took into account decentralised diesel generation, whose share in terms of capacity is large in comparison to the generation.

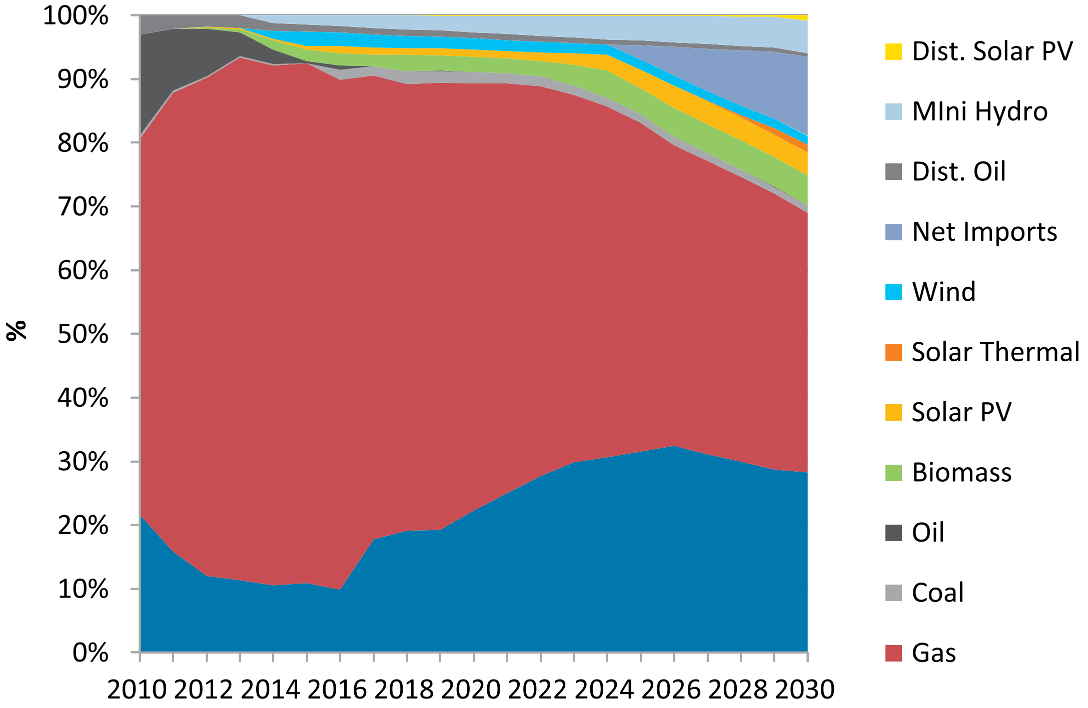

Figure 12. Electricity Supply (Regional Generation plus Import from Central Africa) in the Renewable Scenario

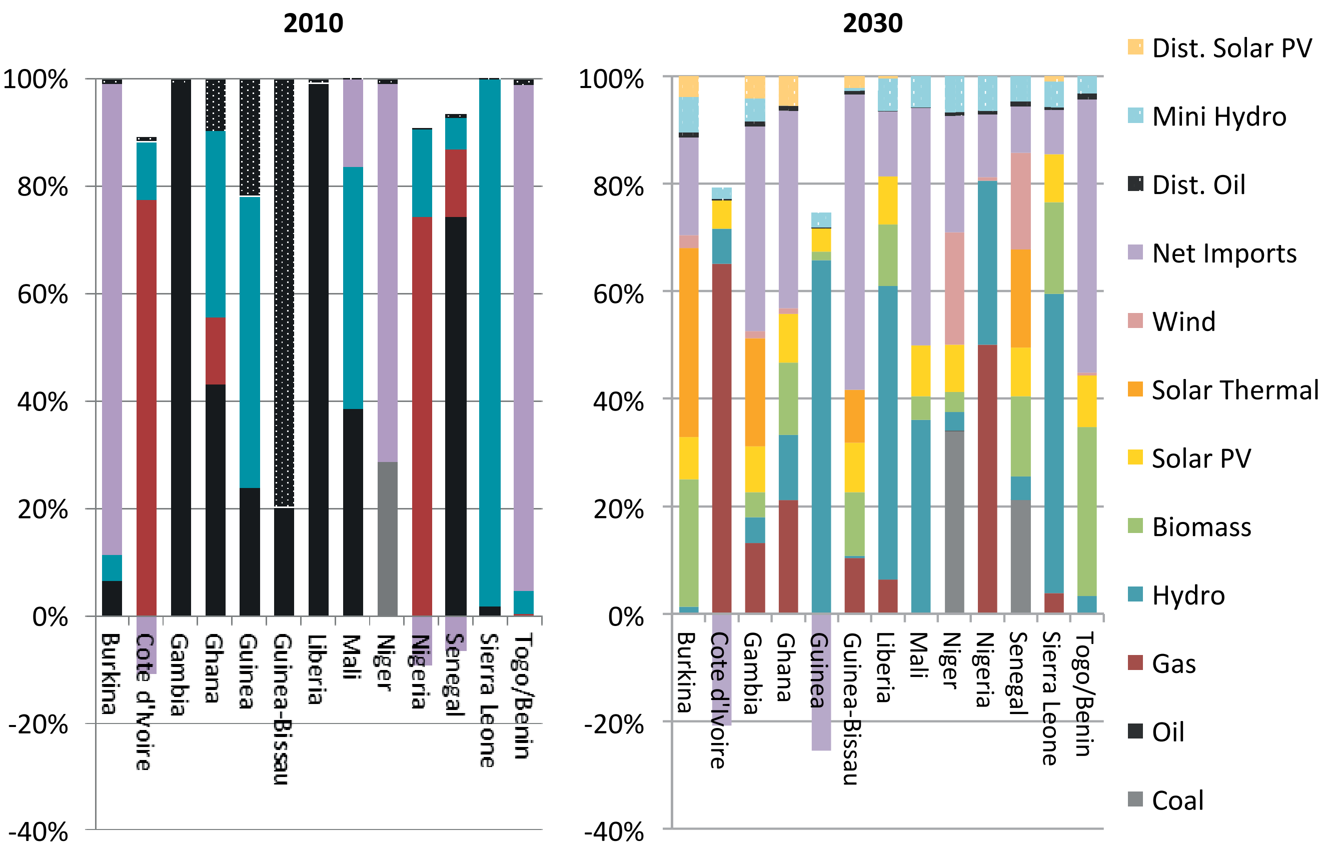

Figure 13. Electricity Production Shares by Country in 2010 and 2030 under the Renewable Scenario

The share of renewables in the regional electricity supply in the Renewable Scenario is 49%, but on a country-by-country basis, much higher penetration is economically favourable in some countries under the Renewable Scenario. In Burkina Faso, Guinea and Mali, the renewable energy penetration becomes virtually 100% by 2030. Hydro plays a major role in Cote d'Ivoire, Guinea Bissau, Liberia, Nigeria and Sierra Leone.

Solar PV, wind, and biomass-based electricity generation do not have high shares in the overall regional electricity generation mix, but on a country-by-country basis, these technologies become an important part of the electricity generation portfolio in some countries. For example, these three technologies together account for more than 90% of the domestically produced grid-connected electricity in Burkina Faso and Togo/Benin[8]. More than 60% is accounted for in Gambia, Guinea-Bissau and Senegal.

Figure 14 shows the regional energy trade flows in 2030. It shows that the main flows are from Democratic Republic of Congo (DRC)/Cameroon to Nigeria, with some of it exported on to Ghana via Benin/Togo, and Niger. There are also export flows from Guinea to surrounding countries: Sierra Leone, Guinea-Bissau, Mali, Senegal and even Cote d'Ivoire via Liberia. Cote d'Ivoire itself exports to Mali, Burkina Faso and Ghana.

Figure 15 shows the share of urban and rural electricity demand met by distributed generation in 2030 for the Renewable Scenario. In urban sectors most of this distributed generation is in the form of rooftop PV with battery with some diesel generation, whereas in rural sectors, in those countries where it is available, most of the distributed generation is in the form of mini-hydro, the difference being met with a mix of diesel generators and rooftop PV with battery.

ZSM©Akosombo Dam is spilling water, Ghana/Wikimedia

[8] Although the share of domestic generation in the total domestic system demand is relatively small, 19% and 30% for Burkina Faso and Gambia respectively,) as the results include a high share of electricity import.

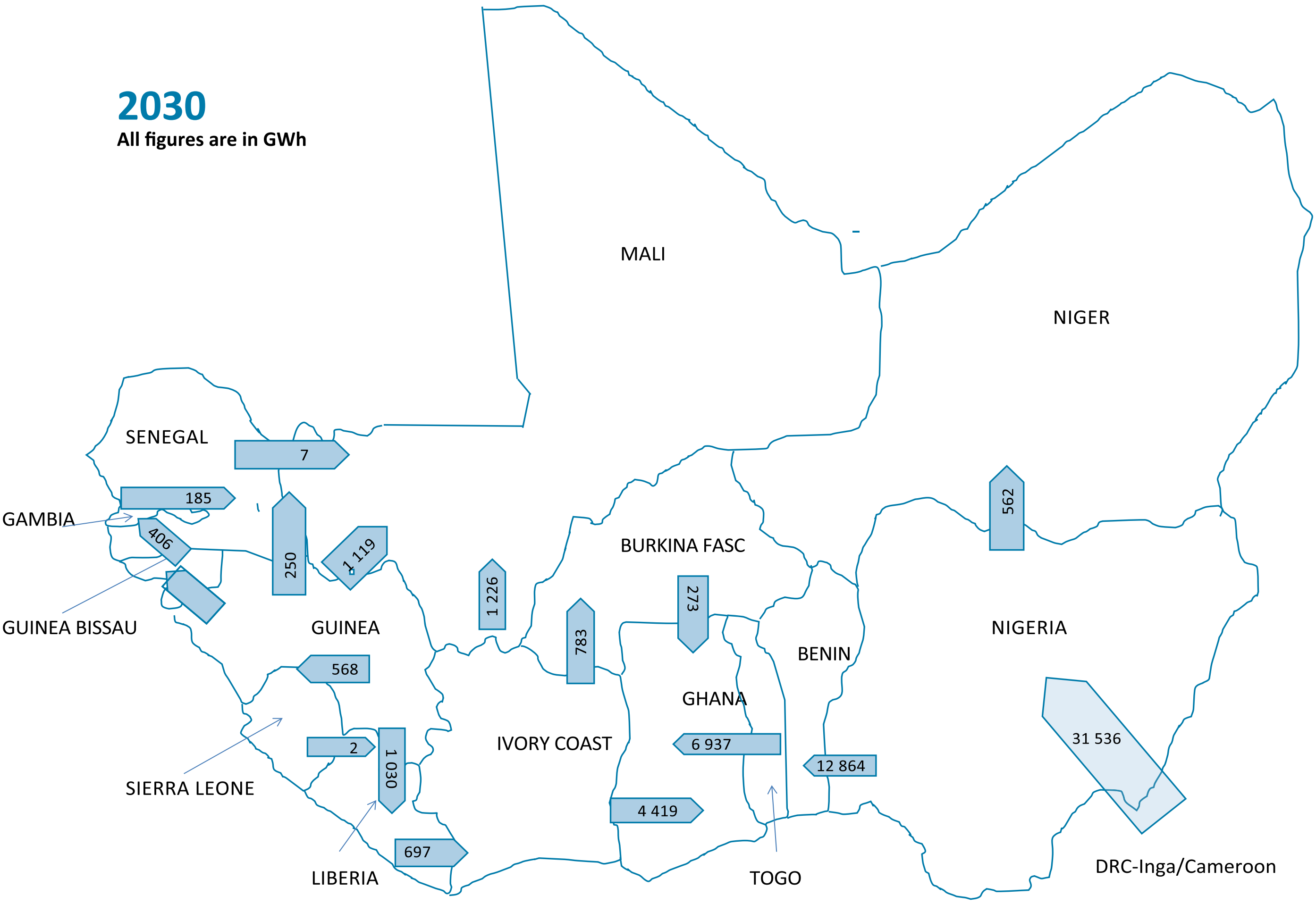

Figure 14. Regional Trade in 2030 in the Renewable Scenario

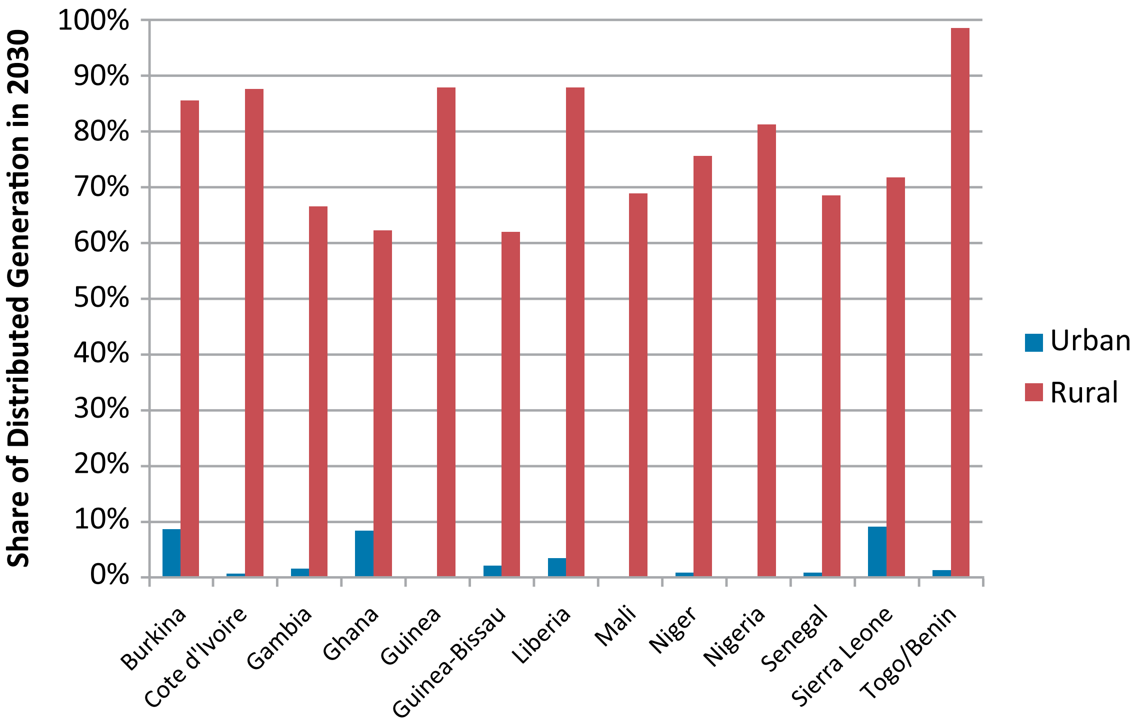

Figure 15. Share of Urban and Rural Electricity Demand met by Distributed Generation in 2030 for the Renewable Scenario

4.3 ECONOMIC IMPLICATION OF THE RENEWABLE SCENARIO

The EREP model computes economic implications of a given scenario in terms of investment cost (in generation and in transmission and distribution), fuel costs, O&M costs, and gain from the carbon finance. The sum of these cost elements constitute the system costs which the model tries to minimize.

Figure 16 shows the undiscounted system costs for selected years in the Renewable Scenario. Investment costs substantially grow to meet the growing electricity demand. Overall investment need in the region between 2010 and 2030 amounts to USD 170 billion (undiscounted) or USD 47 billion (discounted). Note that all prices are expressed in 2010 USD. This investment cost includes estimates of investment in domestic transmission and distribution costs and in the cross-border transmission lines, which add up to about 37% of the total investment costs. The average cost of electricity drops slightly from USD 0.14/KWh in 2010 to USD 0.13/KWh by 2030, mainly due to reduced reliance on expensive liquid fuels for power generation at the beginning of the modelling horizon, which then get replaced first by hydro and then by a combination of coal, gas, RE (including hydro), and imports from Central Africa. This is in contrast to SAPP, where we see a projected increase in average electricity cost (IRENA2013b) in a similar RE scenario. This is because SAPP currently relies on cheaper coal and hydro but then is expected to shift to more expensive low CO_2 options due mainly to the emission reduction aspirations of South Africa. However, by the end of the planning horizon, the average electricity costs in both regions are very similar.

4.4 COMPARISON WITH ALTERNATIVE SCENARIOS

The Renewable Scenario explores how much renewable energy technologies contribute to the least-cost solution under favourable conditions. These conditions include reduction of renewable energy technology investment costs, escalation of fossil fuel prices, and electricity imports from the Central African region providing access to its rich hydro resources. Figure 17 shows the electricity supply shares under Renewable Scenario and two alternative scenarios.

In the Renewable Scenario, imports from Central Africa are included as an available option after 2025. When imports from Central Africa are not allowed, the needed electricity is substituted by the distributed solar PV system, which was not so prominent under the Reference Scenario.

In the Energy Security scenario where electricity import share is limited to 25% by 2030, the overall regional result shown in Figure 17 would not change so much as those that are affected most by this new constraint are relatively small countries. Country by country results are shown in Figure 18. The reduced import in the supply would be replaced mainly by deployment of solar technologies.

In the Renewable Scenario, the average electricity generation costs would decrease from 139 USD/MWh to 128 USD/MWh by 2030, while in the no CA import scenario, it would get 132 USD/MWh implying that the introduction of electricity trade from the Central African region may decrease the average generation costs by 3% by 2030.

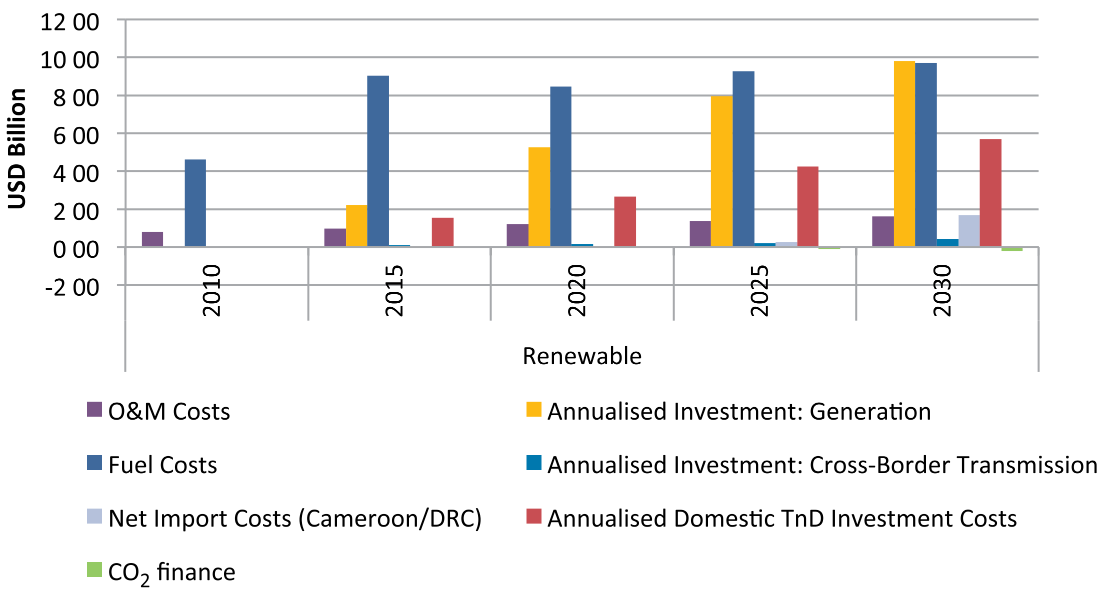

Figure 16. Annualised Undiscounted Costs in the Renewable Scenario

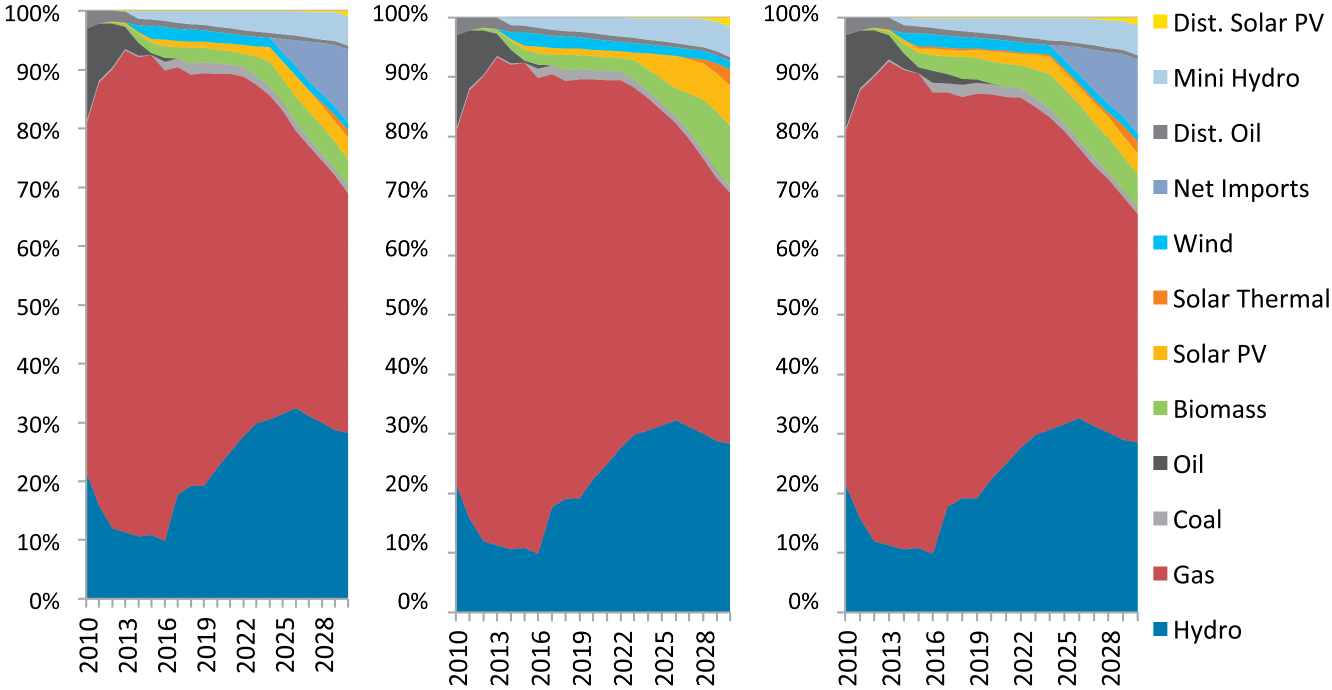

Figure 17. Electricity Supply Shares under Three Alternative Scenarios: Renewable Scenario (left), No Central Africa Import Scenario (middle), and Energy Security Scenario (right)

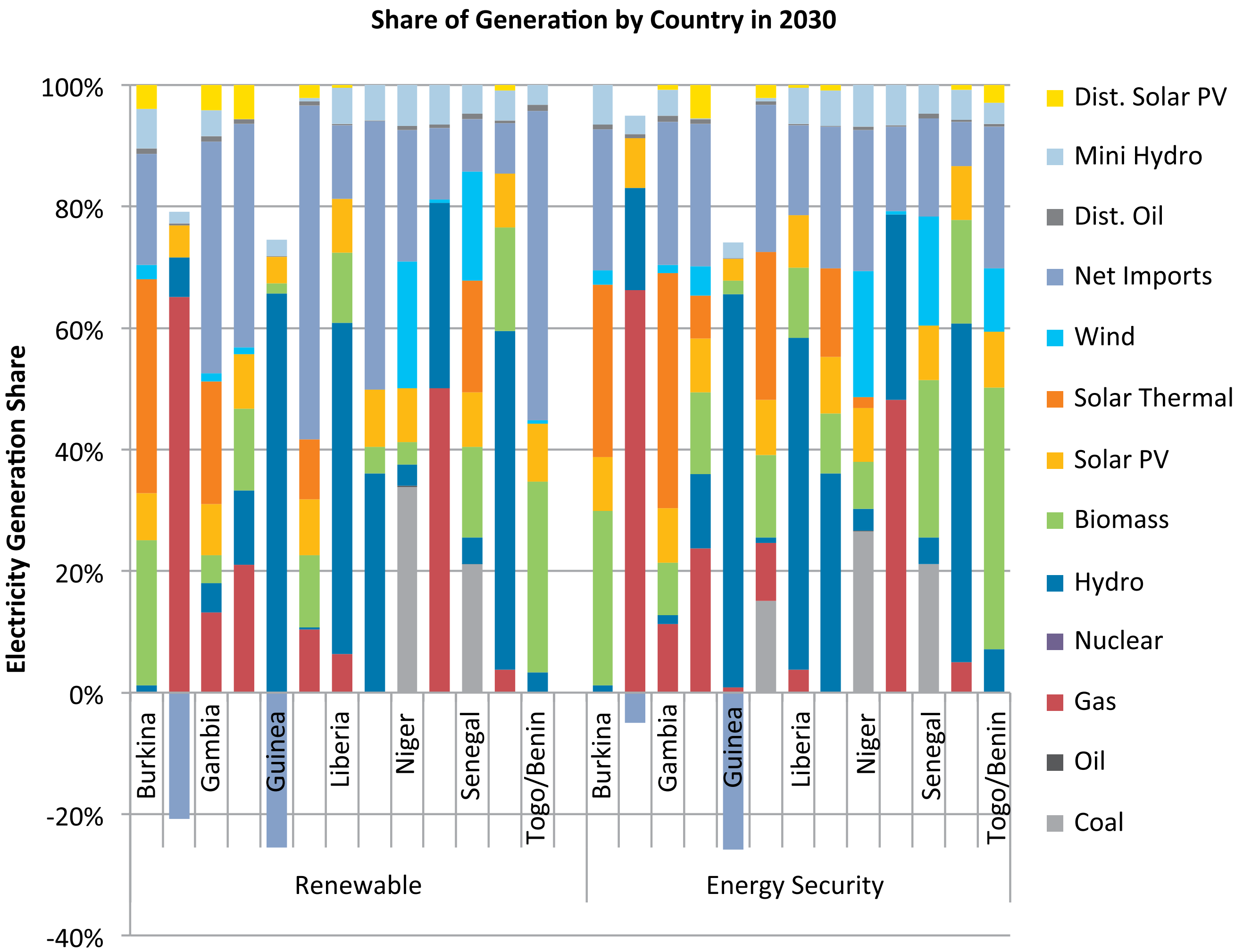

Figure 18. Electricity Supply Mix by Country in the Renewable Scenario vs the Energy Security Scenario

Steve Heap©Water falling 1600 feet down Wli Waterfall near Hohoe in Ghana/Shutterstock

5. Long-term Energy Planning and Integration of Renewable Energy in Power Systems

The EREP model used in this analysis was developed primarily with the aim of assisting IRENA member countries in owing the process of developing long-term renewable integration scenarios and strategies, by transferring it to the interested energy planning offices. In developing such long-term scenarios and strategies, a formal power system modelling technique as shown in this report could serve important roles for two main reasons.

Firstly, it provides rational basis for decision-making. A formal modelling technique assesses the overall investment needs to meet demand, and also helps prioritise alternative investment options based on economic criteria (cost minimisation), as well as on social (import dependency, reliability of supply, rural electrification, etc.) and environmental (emissions of air pollutants and GHG, etc.) criteria. It allows various "what-if" analyses to compare implications of different policy options.

Secondly, processes for developing long-term scenarios using a formal modelling technique provide a platform for consensus-making among stakeholders who may have conflicting objectives. A formal modelling technique does not allow there to be conflicting objectives in the system, as a feasible system may not be able to satisfy all the objectives when they are in conflict.

Concerning the first of these reasons, analytical work using formal modelling tools is a basic "must" in designing a long-term vision of energy sector development. Electricity master plans are typically developed based on full-fledged analysis using such modelling tools. However, in many African countries local capacity to use such tools, or even access to such tools, is often limited. The second reason is that the process of planning is as important as the plan itself, and so having local capacity to use such tools is important. It is worth adding that having local capacity allows the timely updating of a plan, which is often a problem when relying on analysis done by foreign consultancy constancy firms. The landscape surrounding the power sector, and in particular renewable technologies, is rapidly changing and modelling tools allow these changes to be addressed.

Another advantage of owning the process of energy planning using formal modelling tools is that it allows the possible caveats in using such a tool to be fully appreciated. Any model output must be considered in the light of the input data, the model structure and the modelling framework limitations.

It is against this background that IRENA developed the EREP model. Special attention has been focused on the representation of renewable power supply options and their integration into the power system. The aim is to make the EREP model available to interested energy planners and academicians in the region, so that they can use it to explore alternative scenarios for national and regional power sector development. The EREP model provides links to IRENA's latest resource and technology cost assessment. It is configured with the information in the public domain and can be easily updated by the country experts in the region with the latest information which may not be in public domain.

The purpose of this analysis is not for IRENA to develop and to advocate the "renewable transition scenario" for the region. Rather, the scenario presented here is to provide a good and robust starting point for analysts in the region and in respective countries to provoke further discussion about the assumptions and results, and to eventually transfer the model so that the local experts could use it for energy planning purposes. Further scenarios can be built for policy assessments. Energy planning is a continuous process, and modelling tools for decision-making need to be kept alive by constant revision as new information comes in.

In December 2012, IRENA, in corporation with ECOWAS Centre for Renewable Energy and Energy

John Copland©Palm tree dates/Shutterstock

Efficiency (ECREEE), organised a workshop to discuss the role of energy planning in the development of the energy sector and in promoting renewable energies, to present IRENA's EREP model, and to identify areas of collaboration in the field of energy planning. Invited participants from ECOWAS countries, representing energy planning offices in the governments and in utilities in the region, acknowledge that having access to planning tools such as the EREP model is important although access to them and capacity to use them are limited in some countries.

In particular the availability of EREP was considered timely, as ECOWAS countries are developing national renewable deployment plans following the adoption of the ECOWAS Renewable Energy Policy in October 2012 by energy ministers in the ECOWAS counties. Within the framework of this regional policy, National RE Action Plans (NREAP) will start to be developed in the next two years. The EREP model is seen as an appropriate tool to support the NREAP. IRENA, together with its partner organisations, has been planning the setting of a capacity-building support framework.

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6. Conclusions

The EREP model was developed to provide decision-makers and analysts from IRENA Member Countries in the West African region with a planning tool to help design mid- to long-term power systems, prioritises investment options, and assess the economic implications of a given investment path. More specifically, EREP allows analysts to design an energy system that meets various system requirements (including reliability requirements) while taking into account economically optimal configurations (including both investment and operation costs) of the system to meet daily and/or seasonally fluctuating demand.

To summarise, the key features of the EREP model include:

» The projected demand for electricity, data on the existing generation and trans-border transmission infrastructure, data on planned and proposed projects in the West Africa region for new generation as well as for trans-border transmission lines are all taken from the latest WAPP Master Plan for electricity production and transmission (WAPP, 2011).

» The demand for electricity is split into three customer categories, namely: heavy industry; urban residential commercial and small industries; and rural residential and commercial, to allow a better representation of decentralised power supply and improve the representation of the load curve.

» Three customer categories are modelled to require different levels of transmission and distribution infrastructure and incur different levels of losses. They also have access to a different mix of distributed generation options.

» The evolution of renewable energy technology costs and performance is taken from the latest IRENA study.

» Renewable energy potentials were taken from IRENA's new resource assessment studies.

» The nuclear option was excluded from the analysis, as it requires further investigation into technical, legal, and economic challenges, and is outside the scope of this study.

The results presented here should serve as a basis for further discussion. The methodology will be used as a framework for further refinement of general assumptions to reflect perspectives of energy planners in the respective countries.

Two scenarios and two variations were developed using EREP as a basis for further analysis and possible elaboration. They are:

» A Reference Scenario that was configured with consistent assumptions as used in the WAPP Master Plan, with international power trade, no cost reduction for the renewable energy technologies, and with constant fossil fuel costs.

» A Renewable Scenario with international and inter-regional (i.e., from Central Africa) power trade, modestly escalating fossil fuel costs and cost reductions for renewable energy. Two variations were developed, one without electricity imports from Central Africa, the other with limitations on national electricity import share.

» Two variations of the Renewable Scenario were also developed:

  • No Inga Scenario: where imports from Central Africa (DRC/Cameroon) are excluded.
  • Energy Security Scenario: where electricity imports are constrained to 25% by 2030.

The Reference Scenario was developed mainly to benchmark the model with the WAPP Master Plan. The focus of our analysis was on the Renewable Scenario and its variations.

The share of renewable power generation was 22% in 2010. In the Renewable Scenario it rises to 56% (of generation within the region) in 2030. Given a nearly five-fold increase of electricity demand over this period, renewable power generation grows more than ten-fold in absolute terms. The overall contribution of renewables in power generation varies from around 22% in Cote d'Ivoire to 100% in Burkina Faso, Guinea and Mali. Three-quarters of this renewable power supply in 2030 is hydropower generation within the ECOWAS region, supplemented by imported hydropower from central Africa. In the Renewable Scenario, renewables could have a significant impact on increasing access to electricity in rural areas.

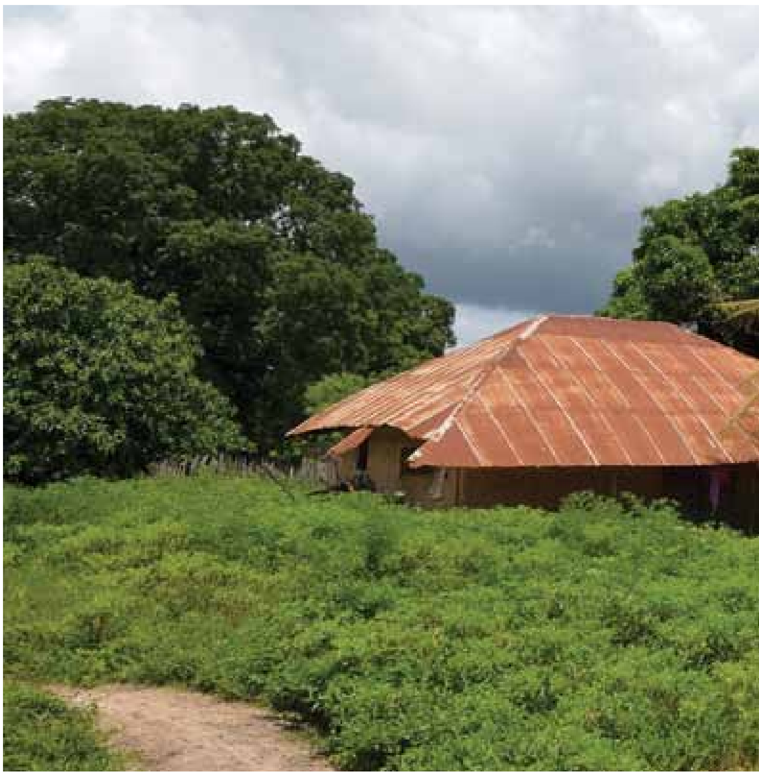
The total capacity additions needed to meet demand over the period of 2010-2030 are calculated as 68 GW, of which one-third is for the decentralised options. The renewable energy technologies accounted for 48% of the total capacity addition in the Renewable Scenario. In the No Inga scenario the share goes up to 56% and in the Energy Security Scenario the share stays at 55%. In all the Renewable Scenario variations, decentralised options play an important role, especially in rural areas.

The investment needed over the period 2010-2030 in the Renewable Scenario is USD 55 billion (discounted). As discussed in IRENA (2011b), adequate electricity provision has been a challenge in the African continent. Reliable, affordable, low-cost power supply is needed for economic growth and renewable energy can play an important role in filling this gap. In particular, African countries are in an enviable position to "choose their future" in energy. The Renewable Scenario assumes relatively rapid reduction of renewable investment costs. Whether this is feasible or not depends on the level of policy and private sector engagement. The policy framework is imperative for successful development of renewable energy.

This report presents a quantitative implication of a "Renewable Scenario" in which all these opportunities are realised by the engagement of governments. It demonstrates the valuable role that renewable energy can play in meeting growing electricity demand in the region. The report does so at a country level, taking into account each of the countries' particularities in terms of composition of demand and available resources, while also considering regional considerations and identifying opportunities for trade benefiting both resource-rich and resource-poor countries.

It is important to note that the assessment presented here is based on certain key assumptions including fuel costs, infrastructure development, and policy developments, which were taken from the assumptions in the WAPP Master Plan. These may well be different from the perspective of the energy planners in respective ECOWAS countries and updated information may be available in respective countries. Since our assessment is strongly influenced by these assumptions, IRENA encourages energy planners to explore different policy assumptions and scenarios that are needed to justify or to elaborate challenges associated with certain investment decisions.

IRENA and ECREEE initiated data validation involving local experts as well as implementation of modelling methodology enhancements. Modelling enhancements include detailed analysis of land use exclusion zones for renewable energy potential assessment, differentiation of capacity factors across countries for solar and wind technologies, better representation of domestic transmission mission line investment connected with higher share of solar and wind technologies.



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Africa924©Typical village to the south of Senegal/Shutterstock

Sierra Pacific©Geothermal plant

Appendix A: Detailed Demand Data

Table 13. Final Electricity Demand Projections in GWh

	Senegal	Gambia	Guinée Bissau	Guinea	Sierra Leone	Liberia	Mali	Ivory Coast	Ghana	Togo/ Benin	Burkina	Niger	Nigeria	Sum
2010	2,494	219	141	608	162	34	1,098	5,814	9,022	2,083	859	835	23,179	47,554
2011	2,654	239	141	608	552	47	1,136	6,005	11,107	2,383	873	849	39,102	65,696
2012	2 991	337	149	760	617	138	1,232	6,390	11,735	2,763	934	912	58,069	87,027
2013	3 147	414	157	934	994	294	1,382	6,799	13,064	3,004	1,006	977	61,321	93,493
2014	3 319	496	167	1,102	1,397	883	2,111	7,245	13,735	3,268	1,087	1,044	64,964	100,818
2015	3,744	586	176	1,563	1,498	1,446	2,226	7,731	14,455	3,547	1,173	1,235	68,830	108,210
2016	4,311	747	538	4,361	2,327	2,119	2,896	8,197	15,223	3,841	1,265	1,306	72,926	120,057
2017	4,536	771	584	4,448	3,102	2,136	2,997	8,680	16,041	4,151	1,362	1,379	77,258	127,445
2018	4,774	796	632	4,542	3,841	2,154	3,153	9,182	16,912	4,478	1,466	1,454	81,856	135,240
2019	5,026	821	683	6,739	5,003	2,174	3,248	9,703	17,840	4,822	1,576	1,530	86,717	145,882
2020	5,306	847	1,086	6,873	6,163	2,195	3,398	10,244	18,828	5,185	1,694	1,609	91,873	155,301
2021	5,624	879	1,142	7,043	6,213	2,218	3,567	10,807	19,879	5,567	1,820	1,691	98,732	165,182
2022	5,933	912	1,166	7,187	6,263	2,242	3,740	11,391	20,998	5,971	1,953	1,774	104,604	174,134
2023	6,261	945	1,192	7,332	6,313	2,268	3,916	11,998	22,189	6,395	2,095	1,860	110,821	183,585
2024	6,611	980	1,218	7,477	6,363	2,295	4,097	12,628	23,456	6,842	2,247	1,948	117,412	193,574
2025	6,983	1,017	1,246	7,626	6,413	2,324	4,282	13,284	24,803	7,314	2,408	2,039	124,393	204,132
2026	7,364	1,055	1,275	7,769	6,462	2,354	4,470	13,963	26,237	7,809	2,579	2,132	131,033	214,502
2027	7,761	1,094	1,306	7,915	6,511	2,387	4,661	14,665	27,764	8,327	2,761	2,226	137,629	225,007
2028	8,175	1,134	1,337	8,061	6,559	2,420	4,855	15,392	29,389	8,870	2,954	2,323	144,139	235,608
2029	8,605	1,176	1,371	8,206	6,605	2,456	5,052	16,144	31,118	9,438	3,159	2,421	150,518	246,269
2030	8,998	1,219	1,403	8,323	6,619	2,491	5,193	16,798	32,985	9,917	3,357	2,497	152,232	252,032
2031	9,466	1,264	1,439	8,470	6,664	2,531	5,397	17,606	34,944	10,540	3,587	2,600	158,507	263,015
2040	14,940	1,751	1,825	9,864	7,146	3,017	7,637	26,862	59,196	18,234	6,523	3,743	227,997	388,733
2050	24,805	2,514	2,436	11,631	7,878	3,967	11,232	42,954	107,560	33,526	12,674	5,611	341,469	608,257

Table 14. Existing Thermal Power Stations

Name of Station	Fuel [9]	Plant Capacity	Available Capacity	Heat Rate	Decommis-sioning Year	Forced Outage	Planned Outage	Variable O&M
		MW	MW	GJ/MWh		%	hr/year	USD/MWh
Senegal								
Steam Turbine	OHF	87.50	53	12.90		8%	613	3.1
Diesel Generators	OHF	280.50	275.5	9.00		10%	960	10
Gas Turbine	ODS	76	66	16.30		8%	613	2.5
Combined Cycle	GAS	52	49	9.20		8%	613	2
Gambia								
Diesel Generators	ODS	6	2.6	12.50		10%	960	10
Diesel Generators	OHF	61	46.6	9.73		10%	960	10
Guinea-Bissau								
Diesel Generators	ODS	5.64	3.7	9.90		25%	960	10
Guinea								
Diesel Generators	OHF	67.68	19	8.90	2012	10%	960	10
Sierra Leone								
Diesel Generators	OHF	45.88	38.7	9.50		10%	960	10
Diesel Generators	ODS	5	5	10.40		10%	960	10
Liberia								
Diesel Generators	ODS	12.64	12.6	11.80		10%	960	10
Mali								
Diesel Generators	ODS	56.85	56.9	9.66		10%	960	10
Gas Turbine	ODS	24.60	20	15.60		8%	613	2.5
Diesel Generators	OHF	57.50	57.5	9.40		10%	960	10

[9] OHF: Heavy fuel oil; ODS: Diesel/Naphta; GAS: Natural gas

Appendix B: Detailed Power Plant Assumptions

Name of Station	Fuel [9]	Plant Capacity	Available Capacity	Heat Rate	Decommis-sioning Year	Forced Outage	Planned Outage	Variable O&M
		MW	MW	GJ/MWh		%	hr/year	USD/MWh
Senegal								
Gas Turbine	GAS	2,960	290	11.40	2013	5%	684	2.5
Gas Turbine	GAS	95.60	84	14.40		3%	693	2.5
Gas Turbine	GAS	214.50	210	12.10		5%	638	2.5
Gas Turbine	GAS	111	111	12.10		5%	636	2.5
Gas Turbine	GAS	70	70	12.10	2013	5%	626	2.5
Ghana								
Combined Cycle	OLC	330	300	8.70		22%	720	5
Gas Turbine	OLC	346	300	12.53		13%	576	6.5
Gas Turbine	ODS	129.50	85	12.33		14%	576	4.5
Combined Cycle	GAS	200	180	8.20		7%	720	2
Togo/Benin								
Gas Turbine	GAS	156	139	13.30	2025	8%	613	2.5
Diesel Generators	ODS	99.3	51.5	10.65	2013	10%	960	10
Diesel Generators	OHF	16	5	12.90	2015	10%	960	10
Burkina Faso								
Diesel Generators	ODS	46	27	10.47		8%	1,289	10
Diesel Generators	OHF	1,328	119	9.63		9%	1,095	10
Niger								
Steam Turbine	COA	32	32	10.80		8%	613	3.1
Diesel Generators	ODS	15.40	4.6	10.40		10%	960	10
Diesel Generators	OHF	12	10	9.50		10%	960	10
Gas Turbine	GAS	20	20	12.70		8%	613	2.5
Nigeria								
Gas Turbine	GAS	4,147.70	2,558.7	12.70		8%	613	2.5
Steam Turbine	GAS	2,229.30	1,299.1	10.57		8%	613	3.1

Table 15. Hydro Existing

Name of Station	Hydro Type [10]	Plant Capacity	Available Capacity	Installation Year	Retirement Year	Forced Outage	Planned Outage	Variable O&M	Average Year	Dry year GWh
		MW	MW			%	hr/year	USD/MWh	GWh	GWh
Senegal										
Manantali (OMVS) part Senegal 33%	DAM	67.65	67.6	1988		5%	570	2	264	165
Guinea										
Baneah	DAM	5	1	1989	2015	5%	570	2	6.4	5
Donkea	ROR	15	11	1970	2015	5%	570	2	72.4	56
Grandes Chutes	DAM	27	3	1954	2015	5%	570	2	127	99
Garafiri	DAM	75	75	1999		5%	570	2	258	204
Kinkon	DAM	3.4	3.4	2006		5%	570	2	11.6	11
Tinkisso	ROR	1.65	1.5	2005		5%	570	2	6.4	5
Sierra Leone										
Goma 1	ROR	6	6	2007		5%	570	2	30.8	1
Bumbuna 1	DAM	50	50	2010		5%	570	2	290	157
Mali										
Selingué	DAM	46.20	43.5	1980		5%	570	2	224.7	198
Sotuba	ROR	5.7	5.7	1966		5%	570	2	38.6	37
Manantali (OMVS) part Mali 52%	DAM	104	104	1988		5%	570	2	420	260
Cote d'Ivoire										
Ayame 1	DAM	19.20	19.2	1998		3%	632	2	60	46
Ayame 2	DAM	30.40	30.4	1998		3%	1,920	2	90	68
Buyo	DAM	164.70	164.7	1980		3%	752	2	900	684
Kossou	DAM	175.50	175.5	2004		3%	856	2	505	384
Taabo	DAM	210.60	190	2004		3%	872	2	850	646
Faye	ROR	5	5	1984		3%	96	2	19	14

[10] DAM: Hydro with a dam, ROR: Run of river.

Name of Station	Hydro Type [10]	Plant Capacity	Available Capacity	Installa-tion Year	Retirement Year	Forced Outage	Planned Outage	Variable O&M	Average Year	Dry year GWh
		MW	MW			%	hr/year	USD/MWh	GWh	GWh
Ghana										
Akosombo	DAM	1,020	900	2005		2%	359	0	4,171	3,100
Kpong	ROR	160	144	1982		2%	359	0.1	880	622
Togo/Benin										
Nangbeto	DAM	65.6	65	1987		5%	504	0	172.7	91
Burkina Faso										
Bagre	DAM	14.40	11	1993	2018	5%	570	2	55.8	21
Kompienga	DAM	12	9	1988	2013	5%	570	2	30.9	16
Niofila	ROR	1.68	1.3	1996	2021	5%	570	2	3.3	3
Tourni	ROR	0.60	0.5	1996	2021	5%	570	2	1	1
Nigeria										
Shiroro	DAM	600	480.3	1989		5%	570	2	2,628	1,945
Jebba	DAM	607.2	458	1986		5%	570	2	2,373	1,401
Kainji	DAM	781.2	420	1968		5%	570	2	2 ,475	1,286

Table 16. Considered and Committed Thermal Generation Projects

Project Name	Plant type [11]	Fuel [12]	Available Capacity	Heat Rate	Start Year	Status	Forced Outage	Planned Outage	Variable O&M	Fixed O&M	Inv. Cost	Life
			MW	GJ/MWh			%	hr/yr	USD/MWh	USD/kW	USD/kW	years
Senegal												
Location	DI	ODS	150	10.4	2011	Committed	10%	960	10	0	1,124	30
new mobile	DI	OHF	150	9.5	2011	Planned	10%	960	10	0	1,418	30
relocation	DI	OHF	120	9.5	2017	Considered	10%	960	10	0	1,418	30
IPP Tou	DI	OHF	60	9.5	2017	Considered	10%	960	10	0	1,418	30
belair	DI	OHF	30	9.5	2012	Committed	10%	960	10	0	1,418	30
unknown	DI	OHF	30	9.5	2017	Considered	10%	960	10	0	1,418	30
Sendou	ST	COA	250	10.8	2016	Committed	8%	613	3.1	0	971	35
Kayar	ST	COA	500	10.8	2017	Considered	8%	613	3.1	0	2,489	35
St Louis	ST	COA	250	10.8	2017	Considered	8%	613	3.1	0	2,489	35
ross betio	BIO	BIO	30	9.6	2014	Committed	8%	613.2	0	130	3,910	30
St Louis WP	WND	WND	125	0	2014	Considered	70%	0	10	17	1,934	20
ziguinchor	SOL	SOL	7.50	0	2014	Considered	75%	0	0	20	5,030	20
taiba ndiaye	WND	WND	100	0	2016	Considered	70%	0	10	17	1,934	20
Gambia												
Brikama	DI	OHF	15.5	9.5	2012	Committed	10%	960	10	0	1,417.5	30
Batokunku	WND	WND	1	0	2012	Committed	70%	0	10	17	1,750	20
Guinea-Bissau												
Bissau	DI	OHF	15	9.5	2012	Committed	10%	960	10	0	1,123.5	30
Guinea												
Tombo (Rehab.)2012	DI	OHF	66.2	9.2	2012	Committed	10%	960	10	0	1,123.5	30
Maneah	DI	OHF	126	9.5	2014	Committed	10%	960	10	0	1,123.5	30
Sierra Leone												
Energeon	ST	BIO	500	10.8	2018	Considered	8%	613	3.1	0	2,489	35
Naanovo	SOL	SOL	5	0	2018	Considered	75%	0	0	20	3,660	20
Addax	BIO	BIO	15	9.6	2018	Considered	8%	613.2	0	130	3,604	30
Liberia												
Bushrod	DI	ODS	10	11.8	2011	Committed	10%	960	10	0	1,124	30
Bushrod 2	DI	OHF	40	9.5	2013	Committed	10%	960	10	0	1,124	30
Kakata (Buchanan)	BIO	BIO	35	9.6	2013	Planned	8%	613.2	0	130	3,604	30

[11] DI: Diesel Systems, ST: Steam Turbine, CC: Combined Cycle, BIO: biomass, WND: wind, SOL: Solar
[12] ODS: Diesel, OHF: Heavy Fuel Oil, COA: Coal, BIO: Biomass, WND: Wind, SOL: Solar

Project Name	Plant type [11]	Fuel [12]	Available Capacity	Heat Rate	Start Year	Status	Forced Outage	Planned Outage	Variable O&M	Fixed O&M	Inv. Cost	Life
			MW	GJ/MWh			%	hr/yr	USD/MWh	USD/kW	USD/kW	years
Mali												
SIKASSO (CO)	DI	ODS	9.2	10.50	2011	Committed	10%	960	10	0	1,124	30
KOUTIALA (CI)	DI	ODS	4.4	10.80	2012	Committed	10%	960	10	0	1,124	30
KANGABA (CI)	DI	ODS	0.5	11.50	2014	Committed	10%	960	10	0	1,124	30
BOUGOUNI (CI)	DI	ODS	2.5	11	2015	Planned	10%	960	10	0	1,124	30
OUELESSEBOUGOU (CI)	DI	ODS	0.4	11.70	2016	Planned	10%	960	10	0	1,124	30
SAN (CI)	DI	ODS	3.7	10.40	2017	Planned	10%	960	10	0	1,124	30
TOMINIAN (CI)	DI	ODS	0.4	11.60	2017	Planned	10%	960	10	0	1,124	30
MOPTI (CI)	DI	ODS	8.4	10.60	2018	Planned	10%	960	10	0	1,124	30
DJENNE (CI)	DI	ODS	0.9	12.40	2018	Planned	10%	960	10	0	1,124	30
Balingue BID	DI	OHF	60	9.50	2011	Committed	10%	960	10	0	1,124	30
VICA BOOT	CC	BIO	30	8.80	2012	Planned	8%	613	2	0	957	25
Albatros BOOT	DI	OHF	92	9.50	2012	Committed	10%	960	10	0	1,124	30
Sosumar 1	BIO	BIO	3	9.60	2014	Planned	8%	613.2	0	130	3,604	30
WAPP CC	CC	ODS	150	8.80	2019	Considered	8%	613	2	0	957	25
WAPP SOLAR	SOL	SOL	30	0	2019	Considered	75%	0	0	20	3,660	20
Mopti SOLAR	SOL	SOL	10	0	2012	Committed	75%	0	0	20	3,660	20
Cote d'Ivoire												
Vridi (CIPREL)	CC	GAS	333	8.80	2014	Committed	8%	613	2	0	957	25
4e centrale IPP (Abbata)	CC	GAS	450	8.80	2014	Planned	8%	613	2	0	957	25
Azito3	CC	GAS	430	8.8	2013	Committed	8%	613	2	0	957	25
G2	CC	GAS	100	8.8	2013	Committed	8%	613	2	0	957	25
Ghana												
Effasu	GT	ODS	100	11.2	2015	Planned	20%	576	4	0	633	25
Aboadze T3 phase 1	CC	OLC	120	8.2	2012	Committed	7%	672	2	0	957	25
Domini T1	CC	OLC	300	11.6	2013	Planned	7%	504	2	0	957	25
Tema T1	CC	OLC	210	11.6	2012	Committed	7%	504	2	0	957	25
Aboadze T2	CC	OLC	100	8.1	2014	Committed	7%	672	2	0	957	25
Sunon Asogli phase 2	CC	GAS	327.20	7.8	2013	Committed	7%	672	2	0	957	25
Aboadze T3 phase 2	CC	OLC	127.30	8.2	2016	Planned	7%	672	2	30	957	25
SolarPV	SOL	SOL	10	0	2012	Committed	75%	0	0	20	3,660	20
Wind	WND	WND	150	0	2014	Committed	75%	0	0	20	1,750	20
Aboadze T4 (WAPP)	CC	GAS	400	7.3	2015	Committed	7%	672	2	30	957	25

Table 16. Considered and Committed Thermal Generation Projects

Project Name	Plant type [11]	Fuel [12]	Available Capacity	Heat Rate	Start Year	Status	Forced Outage	Planned Outage	Variable O&M	Fixed O&M	Inv. Cost	Life
			MW	GJ/MWh			%	hr/yr	USD/MWh	USD/kW	USD/kW	years
Togo/Benin												
CAI	GT	GAS	80	12.7	2011	Committed	8%	613	2.5	0	633	25
IPP_SOLAR	SOL	SOL	20	0	2012	Planned	75%	0	0	20	3,660	20
IPP_WIND	WND	WND	20	0	2013	Planned	70%	0	10	17	1,750	20
IPP_THERMAL	GT	GAS	100	12.7	2013	Planned	8%	613	2.5	0	633	25
CEB_SOLAR	SOL	SOL	10	0	2015	Planned	75%	0	0	20	3,660	20
AFD_SOLAR	SOL	SOL	5	0	2014	Planned	75%	0	0	20	3,660	20
MariaGleta	CC	GAS	450	8.8	2015	Committed	8%	613	2	0	1,984	25
Burkina Faso												
Ouahigouya	DI	ODS	4.3	10.4	2012	Planned	10%	960	10	0	1,124	30
Diebougou	DI	ODS	0.9	10.4	2011	Planned	10%	960	10	0	1,124	30
Gaoua	DI	ODS	1.3	10.4	2011	Planned	10%	960	10	0	1,124	30
Dori	DI	ODS	1.5	10.4	2011	Planned	10%	960	10	0	1,124	30
Gorom-Gorom	DI	ODS	0.3	10.4	2011	Planned	10%	960	10	0	1,124	30
Diapaga	DI	ODS	0.5	10.4	2013	Planned	10%	960	10	0	1,124	30
Komsilga	DI	OHF	91.5	9.5	2011-2013	Committed	10%	960	10	0	1,124	30
Bobo 2	DI	OHF	20	9.5	2012	Committed	10%	960	10	0	1,124	30
Ouaga Solaire	SOL	SOL	20	0	2014	Planned	75%	0	0	20	3,660	20
Mana (SEMAFO)	SOL	SOL	20	0	2012	Planned	75%	0	0	20	3,660	20

Project Name	Plant type [11]	Fuel [12]	Available Capacity	Heat Rate	Start Year	Status	Forced Outage	Planned Outage	Variable O&M	Fixed O&M	Inv. Cost	Life
			MW	GJ/MWh			%	hr/yr	USD/MWh	USD/kW	USD/kW	years
Niger												
TAG Niamey 2	GT	GAS	10	12.7	2011	Planned	8%	613	2.5	0	633	25
Niamey 2	DI	OHF	15.4	9.5	2011	Committed	10%	960	10	0	1,124	30
Goudel	DI	OHF	12	9.5	2012	Planned	10%	960	10	0	2,058	30
Salkadamna	ST	COA	200	10.8	2015	Considered	8%	613	3.1	0	8,575	35
Zinder	CC	GAS	8	8.8	2013	Committed	8%	613	2	0	1,749	25
Wind	WND	WND	30	0	2014	Planned	70%	0	10	17	1,578	20
Solar	SOL	SOL	50	0	2014	Planned	75%	0	0	20	4,322	20
Nigeria												
2011	GT	GAS	2,953.2	12.7	2011	Committed	8%	613	2.5	0	633	25
2012	GT	GAS	4,126	12.7	2012	Committed	8%	613	2.5	0	633	25
2013	GT	GAS	1 ,452	12.7	2013	Committed	8%	613	2.5	0	633	25
ICSPower	GT	GAS	600	12.7	2015	Planned	8%	613	2.5	0	633	25
SupertekNig.	GT	GAS	1,000	12.7	2017	Planned	8%	613	2.5	0	633	25
Ethiope	GT	GAS	2,800	12.7	2017	Planned	8%	613	2.5	0	633	25
FarmElectric	GT	GAS	150	12.7	2015	Planned	8%	613	2.5	0	633	25
Westcom	GT	GAS	500	12.7	2015	Planned	8%	613	2.5	0	633	25

Table 17. Considered and Committed Hydro Projects

Name of Station	Hydro Type	Available Capacity	Start Year	Status	Forced Outage	Planned Outage	Variable O&M	Invest-ment Cost	Average Year	Dry Year
		MW			%	hr/yr	USD/MWh	USD/kW	GWh	GWh
Senegal										
Sambangalou (OMVG) part Senegal 40%	DAM	51	2017	Committed	5%	570	2	3 386	160.8	83.2
Kaleta (OMVG) part Senegal 40%	ROR	96	2016	Planned	5%	570	2	1 114	378.4	90.8
Digan(OMVG) part Senegal 40%	ROR	37	2018	Considered	5%	570	2	1 201	97.0	9.5
FelloSounga (OMVG) part Senegal 40%	DAM	33	2018	Considered	5%	570	2	3 474	133.2	114.4
Saltinho(OMVG) part Senegal 40%	ROR	8	2018	Considered	5%	570	2	4 273	32.8	9.5
Felou(OMVS) part Senegal 15%	ROR	15	2013	Committed	5%	570	2	2 400	87.5	80.0
Gouina(OMVS) part Senegal 25%	ROR	35	2017	Committed	5%	570	2	2 347	147.3	56.8
DAMConsidered	DAM	255	2019	Considered	5%	570	2	4 311	950.8	656.1
Gambia										
Sambangalou (OMVG) part Gambia 12%	DAM	15	2016	Planned	5%	570	2	3 386	48.2	25.0
Kaleta (OMVG) part Gambia 12%	ROR	29	2016	Planned	5%	570	2	1 114	113.5	27.2
Digan (OMVG) part Gambia 12%	ROR	11	2018	Considered	5%	570	2	1 201	29.1	2.8
FelloSounga (OMVG) part Gambia 12%	DAM	10	2018	Considered	5%	570	2	3 474	40.0	34.3
Saltinho (OMVG) part Gambia 12%	ROR	2	2018	Considered	5%	570	2	4 273	9.8	2.8
Guinea-Bissau										
Sambangalou (OMVG) part Guinea Bissau 8%	DAM	3	2016	Planned	5%	570	2	3 386	9.7	5.0
Kaleta (OMVG) part Guinea Bissau 8%	ROR	6	2016	Planned	5%	570	2	1 114	22.7	5.5
Digan (OMVG) part Guinea Bissau 8%	ROR	2	2018	Considered	5%	570	2	1 201	5.8	0.6
FelloSounga (OMVG) part Guinea Bissau 8%	DAM	2	2018	Considered	5%	570	2	3 474	8.0	6.9
Saltinho (OMVG) part Guinea Bissau 8%	ROR	0.5	2018	Considered	5%	570	2	4 273	2.0	0.6

Name of Station	Hydro Type	Available Capacity	Start Year	Status	Forced Outage	Planned Outage	Variable O&M	Invest-ment Cost	Average Year	Dry Year
		MW			%	hr/yr	USD/MWh	USD/kW	GWh	GWh
Guinea										
Baneah (Rehab)	DAM	5	2015	Committed	5%	570	2	2,400	6.4	4.9
Donkéa (Rehab)	DAM	15	2015	Committed	5%	570	2	2,400	72.4	55.5
Grandes Chutes (Rehab)	DAM	27	2015	Committed	5%	570	2	2,400	127.0	99.2
Sambangalou (OMVG) part Guinea 40%	DAM	51.2	2016	Planned	5%	570	2	3,386	160.8	83.2
Kaleta (OMVG) part Guinea 40%	DAM	240	2015	Committed	5%	570	2	1,114	946.0	227.0
Digan (OMVG) part Guinea 40%	DAM	37	2018	Considered	5%	570	2	1,201	97.0	9.5
FelloSounga (OMVG) part Guinea 40%	DAM	32.8	2018	Considered	5%	570	2	3,474	133.2	114.4
DAM Considered	DAM	2,929	2019	Considered	5%	570	2	2,400	12,720.3	10,370.8
Saltinho (OMVG) part Guinea 40%	DAM	8	2018	Considered	5%	570	2	4,273	32.8	9.5
Sierra Leone										
Goma2 (Bo-Kenema)	ROR	6	2015	Planned	5%	570	2	6,709	30.8	1.4
Bumbuna2	DAM	40	2015	Planned	5%	570	2	1,950	220.0	237.0
Bumbuna3 (Yiben)	DAM	90	2017	Planned	5%	570	2	1,950	396.0	317.0
Bumbuna 4&5	DAM	95	2017	Planned	5%	570	2	1,950	494.0	463.0
Benkongor 1	DAM	35	2020	Planned	5%	570	2	2,447	237.2	199.7
Benkongor 2	DAM	80	2022	Planned	5%	570	2	2,447	413.7	338.3
Benkongor 3	DAM	86	2025	Planned	5%	570	2	2,447	513.1	421.1
DAM Considered	DAM	323	2026	Considered	5%	570	2	2,561	1,863.2	1,490.5
Liberia										
Mount Coffee (+Via reservoir)	DAM	66	2015	Committed	5%	570	2	5,803	435.0	344.0
SaintPaul -1B	DAM	78	2017	Considered	5%	570	2	3,123	512.0	389.1
SaintPaul -2	DAM	120	2017	Considered	5%	570	2	3,123	788.0	598.9
DAM Considered	DAM	702.5	2019	Considered	5%	570	2	3,123	3,027.7	2,301.1

Table 17. Considered and Committed Hydro Projects

Name of Station	Hydro Type	Available Capacity	Start Year	Status	Forced Outage	Planned Outage	Variable O&M	Invest-ment Cost	Average Year	Dry Year
		MW			%	hr/yr	USD/MWh	USD/kW	GWh	GWh
Mali										
Sotuba2	ROR	6	2014	Planned	5%	570	2	2,400	39.0	37.4
Kenié	ROR	42	2015	Planned	5%	570	2	3,670.7	199.0	162.6
Gouina (OMVS) part Mali 45%	ROR	63	2017	Committed	5%	570	2	2,347	265.1	102.0
Felou (OMVS) part Mali 45%	ROR	27	2013	Committed	5%	570	2	2,347	265.1	102.0
DAM Considered	DAM	303	2018	Considered	5%	570	2	4,025	1,085.8	825.2
Cote d'Ivoire										
Soubre	DAM	270	2018	Planned	5%	570	2	2,400	1 116.0	0.0
Aboisso Comoé	DAM	90	2026	Considered	5%	570	2	2,756	392.0	297.9
Gribo Popoli	DAM	112	2027	Considered	5%	570	2	3,249	515.0	391.4
Boutoubré	DAM	156	2028	Considered	5%	570	2	2,570	785.0	596.6
Louga	DAM	280	2029	Considered	5%	570	2	4,751	1,330.0	1,010.8
Tiboto / Cavally (Intl.) partCI 50%	DAM	112	2030	Considered	5%	570	2	2,570	600.0	456.0
Tiassalé	ROR	51	2030	Considered	5%	570	2	4,068	215.0	163.4
Ghana										
Bui	DAM	342	2013	Committed	1%	350	0	2,400	1,000.0	0.0
Juale	DAM	87	2014	Considered	1%	350	0.1	3,552	405.0	307.8
Pwalugu	DAM	48	2014	Considered	1%	350	0.1	3,625	184.0	139.8
Hemang	ROR	93	2014	Considered	1%	350	0.1	2,688	340.0	258.4
Kulpawn	DAM	36	2014	Considered	1%	350	0.1	8 111	166.0	126.2
Daboya	DAM	43	2014	Considered	1%	350	0.1	4,698	194.0	147.4
Noumbiel (Intl.) part Ghana 20%	DAM	12	2014	Considered	1%	350	2	4,767	40.6	30.9

Name of Station	Hydro Type	Available Capacity	Start Year	Status	Forced Outage	Planned Outage	Variable O&M	Invest-ment Cost	Average Year	Dry Year
		MW			%	hr/yr	USD/MWh	USD/kW	GWh	GWh
Togo/Benin										
Adjarala	DAM	147	2017	Committed	5%	570	2	2,264	366.0	237.0
Ketou	DAM	160	2018	Considered	5%	570	2	2,105	490.0	372.4
Tetetou	DAM	50	2018	Considered	5%	570	2	3,174	148.0	112.5
Burkina Faso								5,839	192	146
Noumbiel	DAM	48	2021	Considered	5%	570	2	4,767	162.4	123.4
Bougouriba	DAM	12	2021	Considered	5%	570	2	10,125	30.0	22.8
Niger										
Kandadji	DAM	130	2015	Committed	5%	570	2	2,400	629.0	0.0
Gambou	DAM	122	2016	Considered	5%	570	2	4,712	528.0	401.3
Dyodyonga	DAM	26	2016	Considered	5%	570	2	2,293	112.1	85.2
Nigeria										
Mambilla	DAM	2,600	2017	Considered	5%	570	2	1,538	11,205.8	8,516.4
Zungeru	DAM	700	2018	Considered	5%	570	2	1,538	3,016.9	2,292.9

Richard Waters©A solar thermal installation, providing hot water/Shutterstock

Appendix C: Generic Technology Parameters

Table 18. Other Parameters for Renewable Energy Technologies

	Load Factor	O&M	Thermal Efficiency	Construction Duration	Life
	%	USD/MWh	%	Years	Years
Diesel/Gasoline 1 kW system (urban/rural)	30%	33.2	16%	0	10
Diesel 100 kW system (industry)	80%	55.4	35%	0	20
Diesel Centralised	80%	17.0	35%	2	25
Heavy Fuel Oil	80%	15.0	35%	2	25
Open cycle Gas Turbine (OCGT)	85%	19.9	30%	2	25
Combined Cycle Gas Turbine (CCGT)	85%	2.9	48%	3	30
Supercritical coal	85%	14.3	37%	4	35
Small hydro	50%	5.4	-	2	30
Biomass	50%	20.0	38%	4	30
Bulk wind (20% CF)	20%	17.4	-	2	25
Bulk wind (30% CF)	30%	14.3	-	2	25
Solar PV (utility)	25%	20.1	-	1	25
Solar PV (rooftop)	20%	23.8	-	1	20
PV with battery 1h storage	22.5%	19.0	-	1	20
PV with battery 2h storage	25%	17.1	-	1	20
Solar CSP no storage	35%	22.3	-	4	25
Solar CSP with storage	63%	18.9	-	4	25
Solar CSP with gas co-firing	85%	18.9	53%	4	25

Table 19. LCOE Comparisons in 2010

	Grid?	Grid	Ind.	Urban	Rural	Urban + CO_2	Grid	Ind.	Urban	Rural	Urban + CO_2
		LCOE (USD/MWh)					Ranking (cheapest to most expensive)				
Diesel centralised	Y	291	328	414	516	433	19	16	18	19	18
Dist. diesel 100 kW	N	320	320				20	15			
Dist. diesel/gasoline 1 kW	N	604		604	604	645	21		19	20	19
HFO	Y	188	217	285	369	306	17	14	17	18	17
OCGT (imported gas/LNG)	Y	141	167	226	301	243	11	10	12	14	14
CCGT (imported gas/LNG)	Y	90	112	162	229	173	3	3	4	6	4
CCGT (domestic gas)	Y	90	112	162	229	173	3	3	4	6	4
Supercritical coal	Y	101	124	176	244	200	5	5	7	8	10
Supercritical domestic coal	Y	81	102	151	216	175	2	2	2	5	6
Hydro	Y	62	82	128	189	128	1	1	1	4	1
Small hydro	N	107			107		9			1	
Biomass	Y	104	127	181	249	181	7	7	9	10	8
Bulk wind (20% CF)	Y	149	176	237	314	237	13	12	14	16	13
Bulk wind (30% CF)	Y	102	125	178	246	178	6	6	8	9	7
Solar PV (utility)	Y	121	145	201	272	201	10	9	11	13	11
Solar PV (rooftop)	N	143		152	152	152	14		3	2	2
PV with battery (1h storage)	N	250		250	250	250	18		15	11	15
PV with battery (2h storage)	N	323		163	163	163	15		6	3	3
Solar CSP no storage	Y	147	173	234	311	234	12	11	13	15	12
Solar CSP with storage	Y	177	205	271	352	271	16	13	16	17	16
Solar CSP with gas co-firing	Y	106	129	183	251	192	8	8	10	12	9

Table 20. LCOE Comparisons in 2020

	Grid?	Ref. Grid	RE Grid	RE Ind.	RE Urban	RE Rural	Urban + CO_2	Ref. Grid	RE Grid	RE Ind.	RE Urban	RE Rural	Urban + CO_2
		LCOE USD/MWh						Ranking (cheapest to most expensive)					
Diesel	Y	325	325	364	432	533	451	19	19	16	18	19	18
Dist. diesel 100 kW	N	355	355	355				20	20	15			
Dist. diesel/ gasoline 1 kW	N	693	693		693	693	735	21	21		19	20	19
HFO	Y	208	208	238	295	377	315	17	18	14	17	18	17
OCGT (imported gas/LNG)	Y	154	154	180	231	305	247	14	16	13	16	17	16
CCGT (imported gas/LNG)	Y	98	98	120	165	230	175	3	7	6	8	10	7
CCGT (domestic gas)	Y	98	98	120	165	230	175	3	7	6	8	10	7
Supercritical coal	Y	104	104	127	173	239	196	6	9	8	10	12	13
Supercritical domestic coal	Y	89	89	110	154	218	178	2	3	3	5	7	9
Hydro	Y	62	62	82	123	183	123	1	1	1	2	5	2
Small hydro	N	107	97			97		8	6			1	
Biomass	Y	104	92	114	158	222	158	7	4	4	6	8	5
Bulk wind (20% CF)	Y	149	128	152	200	270	200	12	13	11	14	15	14
Bulk wind (30% CF)	Y	102	88	109	153	217	153	5	2	2	4	6	4
Solar PV (utility)	Y	121	94	116	161	226	161	10	5	5	7	9	6
PV with battery (1h storage)	N	152	118		118	118	118	13	11		1	2	1
PV with battery (2h storage)	N	250	181		181	181	181	18	17		11	4	10
PV with battery	N	163	131		131	131	131	15	14		3	3	3
Solar CSP no storage	Y	147	119	143	190	259	190	11	12	10	13	14	11
Solar CSP with storage	Y	177	138	164	213	284	213	16	15	12	15	16	15
Solar CSP with gas co-firing	Y	113	111	135	181	248	191	9	10	9	12	13	12

Table 21: LCOE Comparisons in 2030

	Grid?	Ref. Grid	RE Grid	RE Ind.	RE Urban	RE Rural	Urban + CO_2	Ref. Grid	RE Grid	RE Ind.	RE Urban	RE Rural	Urban + CO_2
		LCOE USD/MWh						Ranking (cheapest to most expensive)					
Diesel	Y	339	339	372	440	552	459	19	19	16	18	19	18
Dist. diesel 100 kW	N	371	371	371				20	20	15			
Dist. diesel/gasoline 1 kW	N	740	740		740	740	782	21	21		19	20	19
HFO	Y	216	216	243	299	389	319	17	18	14	17	18	17
OCGT (imported gas/LNG)	Y	161	161	185	235	315	252	14	17	13	16	17	16
CCGT (imported gas/LNG)	Y	102	102	123	167	236	178	3	8	7	10	11	9
CCGT (domestic gas)	Y	102	102	123	167	236	178	3	8	7	10	11	9
Supercritical coal	Y	106	106	126	172	241	195	7	11	9	12	13	15
Supercritical domestic coal	Y	93	93	113	157	224	180	2	6	5	8	9	11
Hydro	Y	62	62	80	122	183	122	1	1	1	3	5	3
Small hydro	N	107	89			89		8	5			1	
Biomass	Y	104	86	106	149	215	149	6	4	4	6	8	6
Bulk wind (20% CF)	Y	149	117	138	184	256	184	12	15	12	15	16	13
Bulk wind (30% CF)	Y	102	81	100	143	208	143	5	2	2	4	6	4
Solar PV (utility)	Y	121	84	103	146	212	146	10	3	3	5	7	5
Solar PV (rooftop)	N	152	105		105	105	105	13	10		1	2	1
PV with battery (1h storage)	N	250	151		151	151	151	18	16		7	4	7
PV with battery (2h storage)	N	163	110		110	110	110	15	12		2	3	2
Solar CSP no storage	Y	147	102	122	167	236	167	11	7	6	9	10	8
Solar CSP with storage	Y	177	116	137	184	255	184	16	14	11	14	15	12
Solar CSP with gas co-firing	Y	117	115	136	182	253	191	9	13	10	13	14	14

ZSM©Akosombo Dam spilling water, Ghana/Wikimedia

Dennis Schroeder©Pretreatment reactor in the Integrated Biorefinery Research Facility/NREL

Appendix D: Detailed Transmission Data

Table 22. Detailed Data for Existing Transmission Infrastructure

Country 1	Country 2	Line Voltage	Line Capacity	Loss Coefficient	Forced Outage Rate
		kV	MW	%	%
Ghana	Cote d'Ivoire	225	327	220	3.03%
Ghana	Togo/Benin	161x2	310	91.3	2.50%
Senegal	Mali	225	100	1,200	5.46%
Cote d'Ivoire	Burkina	225	327	221.8	3.48%
Nigeria	Togo/Benin	330	686	75	2.50%
Nigeria	Niger	132x2	169.2	162	2.62%

Table 23. Detailed Data for Transmission Projects

From	To	Stations	Voltage	Capacity per Line	Distance	Losses	Total Investment	Investment Cost	Earliest Year
			kV	MW	km	%	USD million	USD/kW	
Dorsale 330 kV (committed)									
Ghana	**Togo/Benin**	Volta - Sakete	330	655.2	240	2.5%	90.0	137.4	2013
Cote d'Ivoire	**Ghana**	Riviera - Presea	330	655.2	240	2%	90.0	137.4	2015
CLSG (committed)									
Cote d'Ivoire	**Liberia**	Man (CI) - Yekepa (LI)	225	337.6	140	2.50%	59.7	176.9	2014
Liberia	**Guinea**	Yekepa (LI) - Nzerekore (GU)	225	337.6	140	2.50%	59.7	176.9	2014
Liberia	**Sierra Leone**	Yekepa (LI) - Buchanan (LI) - Monrovia (LI) - Bumbuna (SI)	225	303.4	580	6.79%	247.5	815.6	2014
Sierra Leone	**Guinea**	Bumbuna (SI) - Linsan (GU)	225	333.7	190	2.50%	81.1	242.9	2014
OMVG (Committed)									
Senegal	**Guinea**	Kaolack (SE) - Linsan (GU)	225	286.3	800	9.37%	289.8	1,012.3	2017
Senegal	**Gambia**	Birkelane (SE) - Soma (GA)	225	340.7	100	2.50%	36.2	106.3	2017
Gambia	**Guinea-Bissau**	Soma (GA) - Bissau (GB)	225	329.1	250	2.93%	90.6	275.3	2017
Guinea-Bissau	**Guinea**	Mansoa (GB) - Linsan (GU)	225	309.6	500	5.86%	181.2	585.0	2017
Corridor Nord									
Nigeria	**Niger**	Birnin Kebbi (NG) -Niamey (NI)	330	653.1	268	3.14%	143.1	219.1	2014
Niger	**Togo/Benin**	Zabori (NI) - Bembereke (TB)	330	649.7	312	3.65%	166.6	256.4	2014
Niger	**Burkina Faso**	Niamey (NI) - Ouagadougou (BU)	330	637.5	469	5.49%	250.4	392.8	2014

From	To	Stations	Voltage	Capacity per Line	Distance	Losses	Total Investment	Investment Cost	Earliest Year
			kV	MW	km	%	USD million	USD/kW	
Hub Intrazonal									
Ghana	**Burkina Faso**	Han (GH) - Bobo Dioulasse (BU)	225	332.2	210	2.50%	67.0	201.7	2014
Burkina	**Mali**	Bobo Dioulasse (BU) - Sikasso (MA)	225	305.8	550	6.44%	175.5	573.9	2015
Mali	**Cote d'Ivoire**	Segou (MA) - Ferkessedougou (CI)	225	319.7	370	4.33%	136.9	428.3	2016
Guinea	**Mali**	Fomi (GU) – Bamako (MA)	225	321.3	350	4.10%	117.6	366.1	2020
Dorsale Mediane									
Nigeria	**Togo/ Benin**	Kaindhji (NG) - Kara/Bembereke/ Parakou (TB)	330	646.7	350	4.10%	164.6	254.6	2020
Togo/ Benin	**Ghana**	Kara/Bembereke/ Parakou (TB) - Yendi (GH)	330	654.5	250	2.93%	117.6	179.7	2020
OMVS									
Mali	**Senegal**	Gouina (MA) - Tambacounda (SE)	225	329.1	250	2.93%	94.6	287.6	2020

Table 24 Detailed Transmission and Distribution Losses by Country

	Transmission Losses	Distribution Losses			
		2010	2020	2030	2050
Senegal					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	20.5%	10%	8%	8%
Rural	5%	25%	20%	20%	20%
Gambia					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	25.0%	10%	8%	8%
Rural	5%	30%	20%	20%	20%
Guinea-Bissau					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	25.0%	10%	8%	8%
Rural	5%	30%	20%	20%	20%
Guinea					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	25.0%	10%	8%	8%
Rural	5%	30%	20%	20%	20%
Sierra Leone					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	25.0%	10%	8%	8%
Rural	5%	30%	20%	20%	20%
Liberia					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	25.0%	10%	8%	8%
Rural	5%	30%	20%	20%	20%

	Transmission Losses	Distribution Losses			
		2010	2020	2030	2050
Mali					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	19.0%	10%	8%	8%
Rural	5%	25%	20%	20%	20%
Cote d'Ivoire					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	19.5%	10%	8%	8%
Rural	5%	25%	20%	20%	20%
Ghana					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	19.5%	10%	8%	8%
Rural	5%	25%	20%	20%	20%
Togo/Benin					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	19.5%	10%	8%	8%
Rural	5%	25.0%	20%	20%	20%
Burkina					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	12.0%	10%	8%	8%
Rural	5%	15%	15%	15%	15%
Niger					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	12.0%	10%	8%	8%
Rural	5%	20%	20%	20%	20%
Nigeria					
Heavy Industry	5%	2%	2%	0%	0%
Urban/Services/Small Industry	5%	12.0%	10%	8%	8%
Rural	5%	30%	20%	20%	20%

Ocean Power Technologies©OPT Power Buoy

Appendix E: Detailed Build Plan in Renewable Scenario

TRANSMISSION PROJECTS

Dorsale

2013 Ghana to Togo/Benin 655 MW

2017 Cote d'Ivoire to Ghana 655 MW

CLSG

2015 Cote d'Ivoire to Liberia 338 MW, Liberia to Guinea 338 MW, Liberia to Sierra Leone 303 MW, Sierra Leone to Guinea 334 MW

OMVG

2017 Senegal to Guinea 286 MW, Senegal to Gambia 341 MW, Guinea to Senegal 286 MW, Gambia to Senegal 341 MW

Hub Intrazonal

2012 Mali to Cote d'Ivoire 320 MW
2013 Ghana to Burkina Faso 332 MW
2015 Ghana to Burkina Faso 332 MW
2016 Guinea to Mali 95MW

Dorsale Mediane

2026 Nigeria to Togo/Benin 67MW
2030 Nigeria to Togo/Benin 418MW

Nigeria – Benin

2025 Nigeria to Togo/Benin 43MW
2026 Nigeria to Togo/Benin 286MW

Central Africa – Nigeria

2025 Central Africa to Nigeria 1 000 MW
2026 Central Africa to Nigeria 1 000 MW
2027 Central Africa to Nigeria 1 000 MW
2028 Central Africa to Nigeria 1 000 MW
2029 Central Africa to Nigeria 1 000 MW
2030 Central Africa to Nigeria 1 000 MW

GENERATION PROJECTS BY COUNTRY

Burkina Faso

Centralised

- 2010 Unserved 10MW
- 2011 Komsilga 56MW
- 2012 Bobo 2 20MW
- 2013 Komsilga 36MW
- 2014 Bulk Wind (30% CF) 29MW
- 2020 Biomass 12MW
- 2021 Biomass 26MW
- 2022 Biomass 24MW, Solar PV (utility) 79MW
- 2023 Biomass 22MW, Solar PV (utility) 5MW
- 2024 Biomass 22MW, Solar PV (utility) 6MW
- 2025 Biomass 30MW, Solar PV (utility) 6MW
- 2026 Biomass 24MW, Solar PV (utility) 6MW
- 2027 Biomass 17MW, Solar PV (utility) 7MW, Solar thermal no storage 26MW
- 2028 Solar PV (utility) 7MW, Solar thermal no storage 108MW
- 2029 Solar thermal no storage 150MW
- 2030 Solar thermal no storage 83MW

De-Centralised

- 2010 Diesel/Gasoline 1kW system (Urban) 1MW
- 2012 Diesel/Gasoline 1kW system (Urban) 4MW
- 2013 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2014 Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2015 Small Hydro 1MW
- 2016 Small Hydro 2MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 3MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 5MW

- 2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 3MW
- 2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 2MW
- 2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 15MW
- 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 16MW
- 2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2026 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2027 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 4MW
- 2028 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 7MW
- 2029 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 3MW
- 2030 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 12MW, Rooftop PV with 1h Battery 64MW

Cote d'Ivoire

Centralised

- 2010 Unserved 28MW
- 2013 5e centrale IPP (Bassam) 430MW, Lushann 100MW
- 2014 Vridi (CIPREL) 222MW, 4e centrale IPP (Abbata) 150MW
- 2015 Vridi (CIPREL) 111MW, 4e centrale IPP (Abbata) 150MW
- 2016 4e centrale IPP (Abbata) 150MW, CCGT 1000MW
- 2017 CCGT 268MW
- 2024 Solar PV (utility) 112MW
- 2026 Solar PV (utility) 468MW
- 2027 Solar PV (utility) 29MW
- 2028 Boutoubré 156MW, Solar PV (utility) 30MW
- 2029 Solar PV (utility) 30MW
- 2030 Tiboto/Cavally(Intl.)partCI50% 113MW, Solar PV (utility) 25MW

De-Centralised

- 2011 Diesel/Gasoline 1kW system (Rural) 6MW, Diesel/Gasoline 1kW system (Urban) 26MW
- 2012 Diesel/Gasoline 1kW system (Urban) 86MW

- 2014 Small Hydro 25MW, Diesel/Gasoline 1kW system (Urban) 27MW
- 2015 Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 24MW
- 2016 Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 23MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 23MW
- 2018 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 23MW
- 2019 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 23MW
- 2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 9MW
- 2021 Diesel/Gasoline 1kW system (Rural) 7MW, Small Hydro 11MW, Diesel/Gasoline 1kW system (Urban) 38MW
- 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 98MW
- 2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 13MW
- 2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 9MW
- 2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW
- 2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 9MW
- 2027 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 10MW
- 2028 Diesel/Gasoline 1kW system (Rural) 7MW, Small Hydro 12MW
- 2029 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 20MW
- 2030 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 12MW, Diesel/Gasoline 1kW system (Urban) 83MW

Gambia

Centralised

- 2012 Brikama 16MW, Batokunku 1MW
- 2014 Biomass 7MW, Bulk Wind (30% CF) 5MW, Solar PV (utility) 11MW
- 2015 CCGT 60MW, Biomass 6MW, Solar PV (utility) 5MW
- 2016 Solar PV (utility) 15MW
- 2019 Solar PV (utility) 3MW
- 2021 Kaleta(OMVG)partGambie12% 1MW, Solar PV (utility) 2MW
- 2022 Kaleta(OMVG)partGambie12% 5MW, Solar PV (utility) 1MW
- 2023 Kaleta(OMVG)partGambie12% 5MW, Solar PV (utility) 1MW
- 2024 Kaleta(OMVG)partGambie12% 6MW, Solar PV (utility) 1MW
- 2025 Kaleta(OMVG)partGambie12% 6MW, Solar PV (utility) 1MW
- 2026 Kaleta(OMVG)partGambie12% 6MW, Solar PV (utility) 1MW
- 2027 Kaleta(OMVG)partGambie12% 1MW, FelloSounga(OMVG)partGambie12% 9MW, Solar PV (utility) 2MW
- 2028 Solar PV (utility) 2MW, Solar thermal no storage 22MW
- 2029 Solar thermal no storage 23MW

» 2030 Solar thermal no storage 31MW

De-Centralised

» 2012 Diesel/Gasoline 1kW system (Urban) 6MW

» 2013 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 7MW

» 2014 Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 3MW

» 2015 Small Hydro 1MW

» 2016 Small Hydro 2MW

» 2017 Diesel/Gasoline 1kW system (Urban) 1MW

» 2018 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 1MW

» 2019 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 1MW

» 2020 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 2MW

» 2021 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 1MW

» 2022 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 7MW

» 2023 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 7MW

» 2024 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 4MW

» 2025 Diesel/Gasoline 1kW system (Urban) 1MW

» 2026 Diesel/Gasoline 1kW system (Urban) 1MW

» 2027 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 2MW

» 2028 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 2MW

» 2029 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 2MW

» 2030 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 2h Battery (roof top - rural) 4MW, Rooftop PV with 1h Battery 20MW

Ghana

Centralised

» 2012 Aboadze T3 phase-1 120 MW, Tema T1 110 MW, 10 MW

» 2013 Sunon Asogli phase-2 327 MW, Bui 342 MW

» 2014 Aboadze T2 330 MW, 50 MW, Bulk Wind (30% CF) 9 MW

» 2015 Tema T1 220 MW, 100 MW, Aboadze T4 (WAPP) 400 MW

» 2022 Biomass 1 MW

» 2023 Biomass 393 MW, Solar PV (utility) 204 MW

» 2024 Biomass 373 MW, Solar PV (utility) 500 MW

» 2025 Solar PV (utility) 359 MW

- 2026 Biomass 223 MW, Solar PV (utility) 61 MW
- 2027 Hemang 93 MW, OCGT 114 MW, Biomass 10 MW, Solar PV (utility) 55 MW
- 2028 OCGT 235 MW, Solar PV (utility) 65 MW
- 2029 OCGT 255 MW, Solar PV (utility) 67 MW
- 2030 OCGT 143 MW, Solar PV (utility) 12 MW

De-Centralised

- 2014 Small Hydro 1 MW, Diesel/Gasoline 1 kW system (Urban) 118 MW
- 2015 Diesel/Gasoline 1 kW system (Urban) 63 MW
- 2016 Diesel/Gasoline 1 kW system (Rural) 6 MW, Diesel/Gasoline 1 kW system (Urban) 65 MW
- 2017 Diesel/Gasoline 1 kW system (Rural) 5 MW, Diesel/Gasoline 1 kW system (Urban) 65 MW
- 2018 Diesel/Gasoline 1 kW system (Rural) 6 MW, Diesel/Gasoline 1 kW system (Urban) 66 MW
- 2019 Diesel/Gasoline 1 kW system (Rural) 6 MW, Diesel/Gasoline 1 kW system (Urban) 66 MW
- 2020 Diesel/Gasoline 1 kW system (Rural) 4 MW, Diesel/Gasoline 1 kW system (Urban) 41 MW
- 2021 Diesel/Gasoline 1 kW system (Rural) 3 MW, Diesel/Gasoline 1 kW system (Urban) 23 MW
- 2022 Diesel/Gasoline 1 kW system (Rural) 3 MW, PV with 1h Battery (rooftop - rural) 9 MW, Diesel/Gasoline 1 kW system (Urban) 24 MW
- 2023 Diesel/Gasoline 1 kW system (Rural) 4 MW, PV with 1h Battery (rooftop - rural) 1 MW, Diesel/Gasoline 1 kW system (Urban) 25 MW
- 2024 Diesel/Gasoline 1 kW system (Rural) 4 MW, PV with 1h Battery (rooftop - rural) 2 MW, Diesel/Gasoline 1 kW system (Urban) 91 MW
- 2025 Diesel/Gasoline 1 kW system (Rural) 5 MW, Diesel/Gasoline 1 kW system (Urban) 107 MW
- 2026 Diesel/Gasoline 1 kW system (Rural) 11 MW, PV with 1h Battery (rooftop - rural) 1 MW, Diesel/Gasoline 1 kW system (Urban) 110 MW
- 2027 PV with 1h Battery (rooftop - rural) 94 MW, Diesel/Gasoline 1 kW system (Urban) 111 MW
- 2028 Diesel/Gasoline 1 kW system (Rural) 19 MW, PV with 2h Battery (rooftop - rural) 35 MW, Diesel/Gasoline 1 kW system (Urban) 106 MW
- 2029 Diesel/Gasoline 1 kW system (Rural) 10 MW, PV with 2h Battery (rooftop - rural) 62 MW, Diesel/Gasoline 1 kW system (Urban) 102 MW
- 2030 PV with 2h Battery (rooftop - rural) 87 MW, Diesel/Gasoline 1 kW system (Urban) 1 MW, Rooftop PV with 1h Battery 604 MW

Guinea

Centralised

- 2012 Tombo 3 (Rehab.)2012 66MW
- 2013 Tombo 3 (Rehab.)2013 35MW
- 2014 Maneah 126MW, Biomass 20MW

- 2015 Baneah(Rehab) 5MW, Donkéa(Réhab) 15MW, GrandesChutes(Réhab) 27MW, Kaleta(OMVG)partGuinée40% 240MW, Biomass 21MW
- 2016 Biomass 22MW, Solar PV (utility) 184MW
- 2019 DAMEnvisagée 586MW, Solar PV (utility) 6MW
- 2020 DAMEnvisagée 586MW
- 2021 DAMEnvisagée 586MW
- 2022 DAMEnvisagée 586MW
- 2023 DAMEnvisagée 586MW
- 2026 Solar PV (utility) 127MW
- 2027 Solar PV (utility) 5MW
- 2028 Solar PV (utility) 5MW
- 2029 Solar PV (utility) 5MW
- 2030 Solar PV (utility) 4MW

De-Centralised

- 2010 Diesel/Gasoline 1kW system (Urban) 4MW
- 2011 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2014 Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2015 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 20MW
- 2016 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 10MW
- 2017 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2018 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2019 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 10MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2020 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 15MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2021 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 7MW
- 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW
- 2025 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 1MW
- 2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW
- 2027 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 7MW
- 2028 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 7MW
- 2029 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 7MW
- 2030 Diesel/Gasoline 1kW system (Rural) 6MW, Small Hydro 9MW

Guinea-Bissau

Centralised

- 2010 Unserved 20MW
- 2012 Unserved 4MW, Bissau 15MW
- 2013 Solar PV (utility) 6MW
- 2014 OCGT 4MW, Biomass 1MW
- 2015 CCGT 17MW, Biomass 2MW
- 2016 CCGT 43MW, Biomass 2MW, Solar PV (utility) 17MW
- 2017 Biomass 2MW
- 2018 Kaleta(OMVG)partGuinéeBissau8% 2MW, Biomass 2MW, Solar PV (utility) 4MW
- 2019 Kaleta(OMVG)partGuinéeBissau8% 3MW, OCGT 4MW, Biomass 2MW, Solar PV (utility) 2MW
- 2020 OCGT 51MW, Biomass 2MW, Solar PV (utility) 17MW
- 2021 OCGT 7MW, Biomass 2MW, Solar PV (utility) 2MW
- 2022 OCGT 1MW, Biomass 2MW, Solar PV (utility) 1MW
- 2023 OCGT 1MW, Biomass 3MW, Solar PV (utility) 1MW
- 2024 OCGT 2MW, Biomass 3MW, Solar PV (utility) 1MW
- 2025 OCGT 2MW, Biomass 3MW, Solar PV (utility) 1MW
- 2026 OCGT 2MW, Biomass 3MW, Solar PV (utility) 1MW
- 2027 Biomass 3MW, Solar PV (utility) 1MW, Solar thermal no storage 6MW
- 2028 Biomass 4MW, Solar PV (utility) 1MW, Solar thermal no storage 6MW
- 2029 Biomass 2MW, Solar PV (utility) 2MW, Solar thermal no storage 16MW
- 2030 Solar PV (utility) 1MW, Solar thermal no storage 16MW

De-Centralised

- 2010 Diesel/Gasoline 1kW system (Urban) 3MW
- 2011 Diesel/Gasoline 1kW system (Urban) 4MW
- 2013 Solar PV (roof top) 1MW
- 2014 Small Hydro 1MW
- 2016 Small Hydro 1MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 4MW
- 2020 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 1h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2021 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 1h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2022 PV with 1h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 1MW

- 2023 PV with 1h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2024 PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2025 PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2026 PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2027 PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2028 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2029 Diesel/Gasoline 1kW system (Urban) 6MW
- 2030 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 2h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 6MW

Liberia

Centralised

- 2011 Bushrod 10MW
- 2013 Bushrod 2 40MW, Kakata (Buchanan) 35MW
- 2014 OCGT 33MW, Biomass 1MW, Solar PV (utility) 37MW
- 2015 MountCoffee(+Viareservoir) 66MW, CCGT 70MW, Biomass 2MW
- 2016 OCGT 5MW, Biomass 2MW, Solar PV (utility) 52MW
- 2017 SaintPaul -1B 78MW, SaintPaul -2 120MW
- 2024 Solar PV (utility) 4MW
- 2025 Solar PV (utility) 1MW
- 2026 Solar PV (utility) 1MW
- 2027 Solar PV (utility) 1MW
- 2028 Solar PV (utility) 1MW
- 2029 Solar PV (utility) 1MW
- 2030 Solar PV (utility) 1MW

De-Centralised

- 2011 Diesel/Gasoline 1kW system (Urban) 2MW
- 2012 Diesel/Gasoline 1kW system (Urban) 4MW
- 2013 Solar PV (roof top) 1MW
- 2014 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 3MW, Solar PV (roof top) 1MW
- 2015 Small Hydro 1MW, Solar PV (roof top) 2MW
- 2016 Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 2MW, Solar PV (roof top) 2MW
- 2017 Small Hydro 2MW

- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2020 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW
- 2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 2MW
- 2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 4MW
- 2023 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2026 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2027 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2028 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW
- 2029 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 4MW
- 2030 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW

Mali

Centralised

- 2010 0 2MW
- 2011 0 2MW, SIKASSO (CO) 9MW, Balingue BID 60MW
- 2012 0 2MW, KOUTIALA (CI) 4MW, VICA BOOT 30MW, Albatros BOOT 92MW, Mopti SOLAR 10MW
- 2013 0 2MW, 27MW
- 2014 0 2MW, Sotuba2 6MW
- 2015 0 2MW, Kenié 34MW
- 2016 0 2MW
- 2017 0 2MW, Gouina(OMVS)partMali45% 63MW
- 2018 0 2MW, DAMEnvisagée 303MW
- 2019 0 2MW
- 2020 0 2MW
- 2021 0 2MW
- 2022 0 2MW, Solar PV (utility) 153MW
- 2023 0 2MW
- 2024 0 2MW, Solar PV (utility) 14MW
- 2025 0 2MW, Solar PV (utility) 7MW
- 2026 0 2MW, Solar PV (utility) 7MW
- 2027 0 2MW, Solar PV (utility) 7MW
- 2028 0 2MW, Solar PV (utility) 7MW

- 2029 0 2MW, Solar PV (utility) 8MW
- 2030 0 2MW, Solar PV (utility) 6MW

De-Centralised

- 2011 Diesel/Gasoline 1kW system (Rural) 1MW
- 2012 Diesel/Gasoline 1kW system (Urban) 4MW
- 2013 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 10MW
- 2014 Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 33MW
- 2015 Small Hydro 2MW
- 2016 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 1MW
- 2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW
- 2021 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW
- 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW
- 2023 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 5MW
- 2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW
- 2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW
- 2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 6MW
- 2027 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW
- 2028 Diesel/Gasoline 1kW system (Rural) 3MW
- 2029 Diesel/Gasoline 1kW system (Rural) 3MW
- 2030 Diesel/Gasoline 1kW system (Rural) 3MW

Niger

Centralised

- 2010 Unserved 115MW
- 2011 Niamey 2 15MW
- 2012 Unserved 68MW, TAG Niamey 2 10MW, Dossou 2MW, Tillabery 2MW, Gaya 1MW, Goudel 12MW
- 2013 Zinder 8MW
- 2014 Wind 30MW, Diesel Centralised 16MW, Biomass 21MW, Bulk Wind (30% CF) 71MW
- 2015 Kandadji 130MW, Bulk Wind (30% CF) 14MW
- 2016 Dyodyonga 26MW, Bulk Wind (30% CF) 5MW
- 2017 Bulk Wind (30% CF) 5MW

» 2018 Supercritical coal 111MW

» 2022 Bulk Wind (30% CF) 26MW

» 2023 Bulk Wind (30% CF) 6MW

» 2024 Bulk Wind (30% CF) 6MW

» 2027 Bulk Wind (30% CF) 17MW, Solar PV (utility) 89MW

» 2028 Bulk Wind (30% CF) 6MW, Solar PV (utility) 3MW

» 2029 Bulk Wind (30% CF) 5MW, Solar PV (utility) 3MW

» 2030 Bulk Wind (30% CF) 4MW, Solar PV (utility) 2MW

De-Centralised

» 2010 Diesel 100 kW system (industry) 1MW

» 2011 Diesel 100 kW system (industry) 4MW

» 2012 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 11MW

» 2013 Diesel/Gasoline 1kW system (Urban) 13MW

» 2014 Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 9MW

» 2016 Small Hydro 2MW

» 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW

» 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW

» 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 1MW

» 2020 Small Hydro 2MW

» 2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW

» 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW

» 2023 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW

» 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW

» 2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 1MW

» 2026 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW

» 2027 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 8MW

» 2028 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 8MW

» 2029 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 8MW

» 2030 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 5MW

Nigeria

Centralised

» 2011 GT 2011 2953MW

- 2012 GT 2012 4126MW
- 2013 GT 2013 1452MW
- 2015 CCGT 1500MW, Bulk Wind (30% CF) 363MW
- 2016 CCGT 1600MW
- 2017 Mambilla 2600MW, CCGT 1700MW
- 2018 Zungeru 700MW, CCGT 1800MW
- 2019 CCGT 1900MW
- 2020 CCGT 1256MW, Hydro 1000MW
- 2021 CCGT 241MW, Hydro 1000MW
- 2022 CCGT 25MW, Hydro 1000MW
- 2023 Hydro 1000MW
- 2024 Hydro 1000MW
- 2025 Hydro 1000MW
- 2026 Hydro 842MW

De-Centralised

- 2011 Diesel/Gasoline 1kW system (Rural) 7MW, Diesel/Gasoline 1kW system (Urban) 1113MW
- 2012 Diesel/Gasoline 1kW system (Rural) 45MW, Diesel/Gasoline 1kW system (Urban) 557MW
- 2013 Diesel/Gasoline 1kW system (Rural) 47MW, Diesel/Gasoline 1kW system (Urban) 47MW
- 2014 Small Hydro 215MW, Diesel/Gasoline 1kW system (Urban) 50MW
- 2015 Small Hydro 33MW, Diesel/Gasoline 1kW system (Urban) 48MW
- 2016 Small Hydro 116MW, Diesel/Gasoline 1kW system (Urban) 67MW
- 2017 Diesel/Gasoline 1kW system (Rural) 26MW, Small Hydro 139MW, Diesel/Gasoline 1kW system (Urban) 66MW
- 2018 Diesel/Gasoline 1kW system (Rural) 28MW, Small Hydro 105MW, Diesel/Gasoline 1kW system (Urban) 64MW
- 2019 Diesel/Gasoline 1kW system (Rural) 31MW, Small Hydro 57MW, Diesel/Gasoline 1kW system (Urban) 62MW
- 2020 Diesel/Gasoline 1kW system (Rural) 31MW, Small Hydro 110MW, Diesel/Gasoline 1kW system (Urban) 43MW
- 2021 Diesel/Gasoline 1kW system (Rural) 46MW, Small Hydro 141MW, Diesel/Gasoline 1kW system (Urban) 1239MW
- 2022 Diesel/Gasoline 1kW system (Rural) 85MW, Small Hydro 222MW, Diesel/Gasoline 1kW system (Urban) 655MW
- 2023 Diesel/Gasoline 1kW system (Rural) 90MW, Small Hydro 168MW
- 2024 Diesel/Gasoline 1kW system (Rural) 48MW, Small Hydro 184MW
- 2025 Diesel/Gasoline 1kW system (Rural) 52MW, Small Hydro 83MW
- 2026 Diesel/Gasoline 1kW system (Rural) 54MW, Small Hydro 195MW
- 2027 Diesel/Gasoline 1kW system (Rural) 82MW, Small Hydro 205MW
- 2028 Diesel/Gasoline 1kW system (Rural) 88MW, Small Hydro 215MW

» 2029 Diesel/Gasoline 1kW system (Rural) 93MW, Small Hydro 224MW

» 2030 Diesel/Gasoline 1kW system (Rural) 74MW, Small Hydro 156MW

Senegal

Centralised

» 2011 Location 150MW

» 2012 belair 30MW

» 2013 Felou(OMVS)partSénégal15% 15MW

» 2014 ross betio 30MW, Biomass 62MW, Bulk Wind (30% CF) 232MW

» 2015 Biomass 66MW, Bulk Wind (30% CF) 29MW, Solar PV (utility) 157MW

» 2016 Sendou 250MW, Biomass 66MW, Bulk Wind (30% CF) 38MW

» 2017 Sambangalou(OMVG)partSénégal40% 51MW, Gouina(OMVS)partSénégal25% 35MW, Bulk Wind (30% CF) 15MW

» 2018 Biomass 53MW, Bulk Wind (30% CF) 15MW

» 2019 Biomass 3MW, Bulk Wind (30% CF) 16MW

» 2020 Bulk Wind (30% CF) 18MW

» 2021 Bulk Wind (30% CF) 21MW, Solar PV (utility) 74MW

» 2022 Bulk Wind (30% CF) 20MW, Solar PV (utility) 12MW

» 2023 Bulk Wind (30% CF) 21MW, Solar PV (utility) 13MW

» 2024 Bulk Wind (30% CF) 23MW, Solar PV (utility) 14MW

» 2025 Bulk Wind (30% CF) 24MW, Solar PV (utility) 14MW

» 2026 Bulk Wind (30% CF) 25MW, Solar PV (utility) 15MW

» 2027 Bulk Wind (30% CF) 25MW, Solar PV (utility) 15MW

» 2028 Kaleta(OMVG)partSénégal40% 1MW, Bulk Wind (30% CF) 27MW, Solar PV (utility) 16MW, Solar thermal no storage 142MW

» 2029 Bulk Wind (30% CF) 30MW, Solar PV (utility) 18MW, Solar thermal no storage 251MW

» 2030 Kaleta(OMVG)partSénégal40% 3MW, Bulk Wind (30% CF) 26MW, Solar PV (utility) 16MW, Solar thermal no storage 123MW

De-Centralised

» 2010 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 3MW

» 2012 Diesel/Gasoline 1kW system (Urban) 49MW

» 2013 Diesel/Gasoline 1kW system (Rural) 3MW, Diesel/Gasoline 1kW system (Urban) 13MW

» 2014 Small Hydro 11MW, Diesel/Gasoline 1kW system (Urban) 8MW

» 2015 Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 15MW

- 2016 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 10MW, Diesel/Gasoline 1kW system (Urban) 18MW
- 2017 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2018 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2019 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2020 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 7MW
- 2021 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 54MW
- 2023 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 18MW
- 2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 13MW
- 2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 20MW
- 2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 8MW
- 2027 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 9MW, Diesel/Gasoline 1kW system (Urban) 26MW
- 2028 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 23MW
- 2029 Diesel/Gasoline 1kW system (Rural) 5MW
- 2030 Diesel/Gasoline 1kW system (Rural) 6MW, Diesel/Gasoline 1kW system (Urban) 24MW

Sierra Leone

Centralised

- 2013 Diesel Centralised 3MW, Solar PV (utility) 16MW
- 2014 OCGT 120MW, Biomass 6MW, Solar PV (utility) 41MW
- 2015 Bumbuna2 40MW, CCGT 111MW, Biomass 6MW, Solar PV (utility) 4MW
- 2016 Biomass 6MW, Solar PV (utility) 35MW
- 2017 Bumbuna3(Yiben) 90MW, Bumbuna4&5 95MW, Biomass 7MW, Solar PV (utility) 33MW
- 2018 Energeon 100MW, Addax 15MW, Biomass 7MW
- 2019 Biomass 8MW, Solar PV (utility) 79MW
- 2020 Benkongor1 35MW, Biomass 8MW, Solar PV (utility) 41MW
- 2021 Biomass 9MW, Solar PV (utility) 1MW
- 2022 Benkongor2 80MW
- 2024 Solar PV (utility) 9MW
- 2025 Benkongor3 86MW, Solar PV (utility) 1MW
- 2026 DAMEnvisagée 323MW, Solar PV (utility) 1MW
- 2027 Solar PV (utility) 1MW
- 2028 Solar PV (utility) 1MW
- 2029 Solar PV (utility) 1MW

De-Centralised

- 2011 Diesel 100 kW system (industry) 38MW, Diesel/Gasoline 1kW system (Urban) 7MW
- 2012 Diesel 100 kW system (industry) 1MW, Diesel/Gasoline 1kW system (Urban) 7MW
- 2013 Diesel 100 kW system (industry) 37MW, Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 10MW, Solar PV (roof top) 5MW
- 2014 Small Hydro 4MW, Solar PV (roof top) 6MW
- 2015 Small Hydro 1MW, Solar PV (roof top) 1MW
- 2016 Small Hydro 6MW, Solar PV (roof top) 6MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2019 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Solar PV (roof top) 8MW
- 2020 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 8MW, Solar PV (roof top) 8MW
- 2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 8MW
- 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW
- 2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 1MW
- 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 8MW
- 2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2026 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 4MW
- 2027 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW
- 2028 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW
- 2029 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 2MW

Togo/Benin

Centralised

- 2010 Unserved 147MW
- 2011 CAI 80MW
- 2012 Unserved 51MW, IPP_SOLAR 20MW
- 2013 IPP_WIND 20MW, IPP_THERMAL 54MW
- 2014 OCGT 39MW, Biomass 46MW
- 2015 MariaGleta 450MW
- 2017 Adjarala 147MW
- 2023 Biomass 51MW, Solar PV (utility) 171MW
- 2024 Biomass 92MW, Solar PV (utility) 113MW
- 2026 Biomass 72MW, Solar PV (utility) 39MW
- 2027 Biomass 92MW, Solar PV (utility) 21MW

- 2028 Biomass 99MW, Solar PV (utility) 22MW
- 2029 Biomass 125MW, Solar PV (utility) 23MW
- 2030 Biomass 124MW, Solar PV (utility) 18MW

De-Centralised

- 2010 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 4MW
- 2011 Diesel 100 kW system (industry) 9MW, Diesel/Gasoline 1kW system (Rural) 2MW, Diesel/Gasoline 1kW system (Urban) 47MW
- 2012 Diesel/Gasoline 1kW system (Urban) 70MW
- 2014 Small Hydro 17MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2016 Small Hydro 2MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW
- 2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2021 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 55MW
- 2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 79MW
- 2023 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 9MW
- 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 13MW
- 2026 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 13MW
- 2027 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW

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